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PACIFIC GAS AND ELECTRIC COMPANY

2017 GENERAL RATE CASE PHASE II

UPDATED AND AMENDED PREPARED TESTIMONY

EXHIBIT (PG&E-8)
VOLUME 1
REVENUE ALLOCATION AND RATE DESIGN

SUPERCEDES EXHIBITS (PG&E-1, 2, 4, 5, 6, AND 7)

(PG&E-8)

PACIFIC GAS AND ELECTRIC COMPANY
2017 GENERAL RATE CASE PHASE II
EXHIBIT (PG&E-8), VOLUME 1
REVENUE ALLOCATION AND RATE DESIGN
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REVENUE ALLOCATION AND RATE DESIGN POLICY

A. Introduction

The second phase, or Phase II, of Pacific Gas and Electric Company's (PG&E) test year 2017 General Rate Case (GRC) is the California Public Utilities Commission's (CPUC or Commission) opportunity to update electric marginal costs and revise the associated revenue allocation and rate design for each customer class. The Commission's decision in this proceeding will set marginal cost, revenue allocation, and rate design policies for the next three years, including the rate design that will ultimately be applied to PG&E's authorized revenue requirements, which are determined in other proceedings.

Rate design in Phase II proceedings can be generally described to include marginal cost of service studies, revenue allocation and rate design.[1] PG&E's marginal cost of service studies are used to support revenue allocation and rate design presented in this exhibit. Revenue allocation is the first step in the rate design process through which individual revenue requirement functions (e.g., distribution or generation) are assigned (or allocated) to each rate group or customer class. Revenue allocation results provide the target levels of revenue based on the fully allocated cost of service. Phase II proposals for revenue allocation would generally adjust revenue for each customer group to better reflect the fully-allocated cost of service results.

The second step in the rate design process is to derive the prices, or rates, that will apply to each rate schedule based on the allocated revenue. PG&E's revenue allocation and rate design proposals are described in the following chapters of this exhibit.

In Section B of this chapter, PG&E describes its rate design policy objectives. To promote consistent policies in setting rates in this proceeding, PG&E sets forth rate design guidelines in Section C that set the stage for specific revenue allocation and rate design proposals in the chapters that follow.

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1 See Exhibit (PG&E-9) for description of PG&E's cost of service studies.

In Section D, PG&E presents the results of its cost studies as reflected in the revenue allocation and also presents its proposal in this proceeding.

In addition, in Section E, PG&E makes its proposals for: (1) how to implement proposals approved in this proceeding; and (2) how to implement revenue requirement changes going forward. In Section F, PG&E reviews other rate-related proposals for consideration in this proceeding.

The remainder of this chapter is organized as follows:

- Section B – Rate Design Objectives
- Section C – Guidelines for Revenue Allocation and Rate Design
- Section D – Revenue Allocation
- Section E – Implementation of Rate Changes
- Section F – Additional Proposals
- Section G – Organization of the Exhibit
- Section H – Conclusion

B. Rate Design Objectives

In this proceeding, PG&E seeks to make progress toward rates that are more cost-based, more economically efficient, and promote greater equity among customers. However, efforts to meet these goals must invariably balance multiple competing objectives including: compliance with statutes and CPUC rules, rate stability, understandability, and customer acceptance. PG&E's revenue allocation and rate design proposals are guided by the following objectives.

1. Cost of Service

Public Utilities Code (Pub. Util. Code) Section 451 requires that the Commission establish rates that are "just and reasonable." Traditionally, "just and reasonable" rates are based on the cost of service.[2] The costs of providing utility services vary with customer usage characteristics and with the facilities needed to serve a customer. The Commission has a long

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2 See Bonbright, Danielson, and Kanerschen, Principles of Public Utility Rates, specifically, Chapter 5, "Cost of Service as a Basic Standard of Reasonableness."

history of using Equal Percent of Marginal Cost (EPMC) to establish a cost-based allocation of revenue among customer classes.[3]

In this proceeding, PG&E proposes using the same general EPMC approach for generation and distribution revenue allocation. Under this approach, each customer class is assigned revenue responsibility for generation and distribution, respectively, in proportion to the marginal cost of generation and distribution service for that class, such that the total revenue for each component is collected.[4] PG&E also uses marginal cost relationships in the rate design process to develop individual rate components for various rate schedules.

The Commission has consistently held that utilities' underlying marginal costs should be the basis for revenue allocation and rate design so that customers receive clear and appropriate cost-based price signals associated with their usage characteristics.[5] Doing so encourages more efficient use of energy and the delivery system. Further, appropriate price signals help prevent un-economic decision-making by customers. The EPMC method makes good policy sense for distribution and generation because it provides a more equitable and economically efficient basis for the allocation of PG&E's distribution- and generation-related revenue requirements.

2. Rate Stability

While it is important to move toward more appropriate, economically-efficient and cost-based price signals, this goal should be balanced with a concern for mitigating change which may include sudden and unduly large bill increases. Historically, mitigation of change

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3 See Exhibit (PG&E-9), Chapter 1 for background with regard to the use of marginal cost for cost of service. PG&E uses the terms "full cost" and "full EPMC" revenue responsibility interchangeably in this exhibit.

4 Marginal costs are provided in Exhibit (PG&E-9).

5 In D.15-07-001, addressing residential rate reform, the Commission described 10 rate design principles. Many support cost based rate design. For example, (2) Rates should be based on marginal cost. (3) Rates should be based on cost causation principles. (4) Rates should encourage reduction of both coincident and non-coincident peak demand. (7) Rates should generally avoid cross subsidies, unless the cross subsidies appropriately support explicit state policy goals. (9) Rates should encourage economically efficient decision making. (See p. 28).

has included a combination of the moderation of the changes made in both revenue allocation and in rate design. In this proceeding, PG&E specifically acknowledges the substantial changes that customers will be experiencing in rate design over the next few years, and for that reason, recommends minimizing changes in revenue allocation. Rate design changes already planned for implementation during the next few years include: (1) completion of the migration of non-residential customers to mandatory time-of-use (TOU) rates; (2) continuation of the default to Peak Day Pricing (PDP) for selected non-residential customer groups; (3) continuation of residential tier rate reform, including implementation of the Super User Electric surcharge, adopted in Decision (D.) 15-07-001, for customers with usage in excess of 400 percent of their baseline quantity; and (4) implementation of residential default TOU rates beginning as early as 2019. In this proceeding, PG&E also proposes a change to all non-residential TOU periods to align those hours with updated peak periods that are significantly later in the day. PG&E believes this change alone warrants extra care when considering proposals in Phase II. Accordingly, PG&E recommends no change to the current generation and distribution revenue responsibility for each class, but recommends small changes to allocation of certain elements of Public Purpose Program (PPP) rates.

PG&E's proposal to minimize the changes to revenue allocation in this proceeding is unique. In changing to new mandatory TOU periods, PG&E will revise nearly every aspect of rate design for non-residential customers. This will be a significant change for customers. Minimizing the change in revenue allocation is intended to reduce change where it is possible to do so. While certainly not directly offsetting the changes resulting from the change in TOU periods, it incrementally reduces the change that otherwise could have been proposed in this proceeding.

3. Understandable, Meaningful and Practical to Implement

Along with economically efficient, cost-based pricing, rates should empower customers to take actions to control their energy expenses. Rates should be meaningful in that they allow customers to make choices that permit operational changes that will allow them to reduce their energy expenses. In order to accomplish this objective, rates should be understandable and as simple as possible while retaining appropriate price signals. Further, rates must be practical for PG&E to implement. PG&E's proposals seek to balance the increasing complexity of rates, with the need to provide rates and rate options that empower customers to take actions to reduce their energy expenses.

C. Guidelines for Revenue Allocation and Rate Design

In this proceeding, PG&E is proposing changes in revenue allocation and rate design for PPP, and in rate design for the distribution and generation components of rates. In addition, the proposed changes to rates affect both the residential Conservation Incentive Adjustment (CIA) rate and the California Alternate Rates for Energy (CARE) surcharge which is a component of the PPP rate.[6]

The most significant change in this proceeding is the introduction of updated, new TOU periods for use in revenue allocation and rate design. Concurrent with this proceeding, in Rulemaking (R.) 15-12-012, the Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future TOU Rates and Energy Resource Contract Rates (the TOU Periods OIR), the Commission is separately considering how TOU periods should be determined.[7] PG&E's proposals in this proceeding are made based

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6 Total rates consist of a number of different functions including: distribution; transmission; generation; Nuclear Decommissioning; PPP; Competition Transition Charges (CTC); New System Generation Charges; Energy Cost Recovery Amount; Department of Water Resources (DWR) Bond; and greenhouse gas allowance volumetric and by semi-annual credits. In addition, Direct Access (DA) and Community Choice Aggregation (CCA) customers pay the Power Charge Indifference Adjustment (PCIA) and the Franchise Fee Surcharge. Transmission charges are regulated by the Federal Energy Regulatory Commission (FERC) and are not subject to change in this proceeding. PG&E's proposals for change in this proceeding are limited to rates for PPP, generation and distribution.

7 In particular, the Commission has solicited the input and guidance from the California Independent System Operator to better inform the process of setting TOU periods. In spite of this concurrent effort, the Commission has also indicated that efforts in individual utility rate proceedings should not be delayed due to the TOU Periods OIR (see e.g., TOU Periods OIR, R.15-12-012, mimeo, p. 3). Further, PG&E believes certain issues may be utility specific (e.g., setting TOU periods to capture distribution as well as generation peak loads). A proposed decision in the TOU Periods OIR was issued on November 1, 2016, and it is currently on the agenda for the Commission's December 15, 2016 decision conference.

on its understanding of the appropriate approach to setting TOU periods for both generation and distribution. However, additional guidelines may be articulated later this year by the Commission as a result of the TOU Periods OIR, which may subsequently need to be incorporated into PG&E's proposals. Accordingly, PG&E reserves the right to adjust its proposed TOU period proposals based on the Commission's guidance in its final decision in the TOU Periods OIR.

Revenue allocation and rate design guidelines are described in the sections below. Specific rate design proposals described in the following chapters may vary from the guidelines below where judgment or practical considerations indicate that fully implementing the guidelines would produce an unacceptable result, as measured against the objectives for this proceeding.

1. Distribution Revenue Allocation and Rate Design

PG&E's proposed distribution rates are designed to collect the distribution revenue determined using current rates at forecast 2017 billing determinants. In this section, PG&E describes the broad principles used to make rate design recommendations for individual distribution rate components. This section includes the design basis for the customer charge and distribution demand and energy charges, which may vary by season and by TOU period.

a. Customer Charge

Distribution revenue includes all customer and distribution-related cost elements. Therefore, the customer charge is assigned entirely to the distribution rate component of each tariff. PG&E's proposed monthly customer charges are adjusted to better reflect their full, cost-based levels.[8] These levels are derived by scaling up class-specific customer marginal costs by the EPMC multiplier associated with PG&E's

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8 Customer charges have long been included in non-residential rates, and PG&E's proposals in this proceeding relate primarily to those non-residential customer charges. For the residential class, pursuant to the Residential Rate Reform Order Instituting Rulemaking (RROIR) decision (D.15-07-001), PG&E presents in this proceeding a report categorizing what residential costs are fixed, with the understanding that any proposal to include a mandatory fixed charge in residential rates would be proposed, concurrent with PG&E's default TOU rate proposals required to be filed on January 1, 2018, for implementation a year after default TOU has been launched. (See D.15-07-001, mimeo, p. 193.) Accordingly, PG&E is not proposing a residential customer charge for default residential service at this time.

distribution revenue. Where the proposed customer charge does not collect the fully scaled marginal cost, residual customer-related revenue responsibility will necessarily be assigned to the demand and/or energy charge components of the distribution rates applicable under each rate schedule.

b. Distribution Demand and Energy Charges

As a general principle, PG&E recommends that distribution revenue that is not collected in the customer charge should be collected in demand charges, since customer demands are the primary drivers of distribution capacity costs. Historically, the practical application of this principle has been tempered by the simple fact that most residential and small commercial customers have not been demand-metered. In this proceeding, PG&E proposes to develop and apply demand charges on an optional basis in the residential and small commercial sectors where they have not previously been employed. Where application of full cost demand charges would create significant bill impacts, PG&E may recommend reduced levels of recovery of distribution costs in demand charges, with any residual revenues collected through energy charges.

c. Time Differentiation of Distribution Demand and Energy Charges

The last step in distribution rate design is to determine the degree of time differentiation for demand and energy charges by season and TOU period. In general, only distribution primary marginal costs are peak-related (that is, those costs caused by distribution system peak conditions) and subject to collection through time-differentiated charges. Accordingly, PG&E developed distribution primary marginal cost revenue for each of the new TOU periods.[9] PG&E then used these peak-related marginal primary distribution costs to differentiate prices by season and TOU period. All remaining distribution costs (i.e., those not used to derive differentiated charges by season or time period) are assigned as either a flat demand or energy charge adder (i.e., a charge that does not vary by season or TOU period).

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[9] See Exhibit (PG&E-9), Chapter 12.

PG&E further recommends that time differentiation of distribution revenue be limited to schedules with partial and on-peak periods during the summer. This distinction is intended to allow a longer period for collection of peak related distribution costs consistent with the greater diversity of peak loads on PG&E's distribution system. Accordingly, where PG&E proposes only peak and off peak periods in rate design, with no summer partial peak period, distribution rates will not vary by TOU period but will typically vary by season.

Unless noted in the detailed chapters on rate design, PG&E has applied the TOU periods in Exhibit (PG&E-9), Chapter 12 to distribution rate design.[10]

2. PPP Revenue Allocation and Rate Design

PPP revenue includes three components: (1) the former Public Goods Charge (PGC) portion of Energy Efficiency (EE) and the Electric Program Investment Charge (EPIC); (2) Procurement EE and Energy Savings Assistance (ESA); and (3) the CARE surcharge, which funds the cost of the low-income CARE Program. PG&E's proposal for PPP revenue allocation and rate design is based on allocating the revenue requirement separately for each component of PPP revenue and then summing those allocated pieces. In this proceeding, PG&E proposes to use a common allocation for PGC-EE, EPIC, Procurement EE and ESA. In general, the allocation of these items has been developed over time based on policies in place as the components were added.[11] As a result, today there are small differences in the allocation of these rate components. PG&E does not believe that the small differences in allocation of these program costs that exist in rates today make sense going forward. Accordingly, PG&E is proposing to utilize equal percent of total bundled revenue (with generation revenue imputed for

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[10] See Exhibit (PG&E-9), Chapter 12 for notation; the proposed summer season is June through September. The proposed non-residential TOU periods are: (1) on-peak from 5 p.m. to 10 p.m. in all months and all days of the week; (2) partial peak period in the summer months from 3 p.m. to 5 p.m. and from 10 p.m. to midnight in all days of the week; and (3) all other hours are off-peak.

[11] For example, Pub. Util. Code Section 299.8(c)2 provides for a rate cap on funding for the PGC components of EE, renewable energy, and research, development and demonstration programs from January 1, 2002 through January 1, 2012.

DA/CCA customers) as the basis for allocation of all four of the revenue requirement functions that contribute to the non-CARE portion of the PPP rates. This approach was initially the basis for the non-CARE portions of the original PGC and is reasonable to use going forward. PG&E believes that updating this same allocation factor and applying it across all non-CARE portions of the current PPP rate appropriately removes differences in the allocation of these costs and provides a more equitable allocation among customer groups. In general, PG&E applies the same PPP rate in each customer class, differentiated by voltage. In the agricultural class, PG&E proposes to differentiate the PPP rate by rate schedule in recognition that the size of individual accounts within the class can vary significantly.

As a result of revenue allocation and rate design changes in this proceeding, the CARE discount is recalculated and the CARE surcharge component of the PPP rates is revised. Specifically, PG&E proposes to retain the method currently used to determine the CARE shortfall revenue requirement and to allocate the total CARE surcharge revenue requirement among non-exempt customers on an equal-cents per kilowatt-hour (kWh) basis. PG&E proposes to reset the CARE surcharge rates when implementing this decision and to retain the current practice to reset the CARE surcharge once per year thereafter on January 1 in the Annual Electric True-Up (AET) proceeding.

3. Generation Revenue Allocation and Rate Design

PG&E’s proposed generation rates are designed to collect the generation revenue determined using current rates at forecast 2017 billing determinants. In this section, PG&E describes the broad principles used to make rate design recommendations for individual generation rate components. This section includes the design basis for demand and energy charges, which may vary by season and by TOU period.

Marginal generation capacity costs vary by time of day and are assigned to the summer peak and part-peak periods. Marginal generation energy cost revenue is also developed and assigned to TOU periods. In this proceeding, PG&E has assigned marginal generation cost revenue to each of the new non-residential TOU periods set forth in Exhibit (PG&E-9), Chapter 12. Like distribution, PG&E proposes to base its proposed generation rates on marginal generation cost differences by season and TOU period. PG&E proposes to collect generation capacity costs in either TOU demand charges, energy charges, or both.

PG&E's basic TOU rates for non-residential customers will also include a super off-peak period to differentiate generation pricing to set low rates to incent greater consumption during periods likely to see significant over-generation that can cause negative generation prices.[12] PG&E's basic rate design is developed without the super off-peak period. Revenue neutral adjustments are then developed so that they can be added directly to the standard rates. While revenue neutral adjustments were developed outside the normal rate design calculations, they will be presented as part of each TOU rate schedule and not presented in tariffs as incremental adders or credits. PG&E estimates that the rate credit applied to develop super off-peak pricing is about 1.5 cents per kWh. The revenue neutral adder is applied to all winter hours except the super off-peak period and varies from class to class. In most cases, the revenue adder to be applied during non-super off-peak hours ranges from about 0.14 to 0.17 cents per kWh.[13]

Unless otherwise noted; in the following chapters, PG&E has used the TOU period recommendations from Exhibit (PG&E-9), Chapter 12 to calculate generation rates.

4. Total Bundled Rate Calculation

As noted above, in this proceeding, PG&E is proposing changes only to rates for distribution, generation and PPP. Rates for all other functional revenue requirement components remain unchanged in illustrative rates presented for approval in this proceeding. In general, rates for each functional revenue requirement component are added together to determine the total bundled rate.

However, total residential rates that include rate tiers are determined differently. In general, total bundled tiered rates are first determined to

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[12] See Exhibit (PG&E-9), Chapter 12 for description; the proposed super off-peak period is from 10 a.m. to 3 p.m. for all days of the week during the winter months of March, April and May.

[13] See Exhibit (PG&E-8), Appendix B for PG&E's proposed revenue neutral adjustments and the proposed super off-peak prices.

collect the total revenue, and then rates are unbundled to each functional revenue requirement component and the CIA is set residually. Rate design changes for total residential tiered rates in 2017, 2018 and 2019 are dictated by the requirements of residential rate reform as set forth in D.15-07-001, in the RROIR. These include specific reforms to rate tiers, and implementation of default TOU rates for eligible residential customers as early as 2019.[14]

5. Revenue-Neutral Rate Design

PG&E proposes that where customers have choice between rate schedules within a customer class, rates for those schedules be designed on a revenue neutral basis. This will eliminate disparities in current rates where one rate schedule may be set significantly below the level of another rate schedule. In order to develop proposed rates for each customer class that will be revenue-neutral, PG&E uses the combined billing determinants and load characteristics of all customers in the class to first design the rates associated with the entire group. Then, rates for optional rate schedules are designed to collect revenue that would be generated from the rates for the entire group for only the customers taking service under the optional schedules. In many cases, rate schedules have already been established at revenue neutral levels (e.g., Schedules E-6 and A-6). In this proceeding, PG&E proposes to apply revenue neutral rate design in residential, agricultural and small and medium light and power rate classes.

D. Revenue Allocation

In Table 1-1, below, PG&E summarizes its revenue allocation proposal. As discussed above, this proposal adjusts non-CARE PPP rates (i.e., those components of the PPP rate excluding the CARE surcharge) based on allocating all these costs using total bundled revenue with generation imputed for DA/CCA customers. Present rates are based on rates effective October 1, 2016.

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14 In this proceeding, PG&E is proposing additional changes to residential rates including: (1) revised gas and electric baseline quantities; (2) revised master meter discounts; (3) updated practices for medical baseline; (4) updated TOU and electric vehicle rates; and (5) a new residential rate option that includes a maximum demand charge and a customer charge.

TABLE 1-1
PROPOSED REVENUE ALLOCATION RESULTS

Line No.	Customer Class	Bundled Average Change Present Rate	Bundled Average Change Proposed Rate	Bundled Average Change Change	DA/CCA Average Change Present Rate	DA/CCA Average Change Proposed Rate	DA/CCA Average Change Change
1	Residential Total	0.19733	0.19659	-0.38%	0.14596	0.14909	2.14%
2	Small Light and Power	0.22643	0.22627	-0.07%	0.15546	0.15526	-0.13%
3	A-10	0.20027	0.20060	0.16%	0.10839	0.10876	0.34%
4	E-19	0.17536	0.17558	0.13%	0.08575	0.08579	0.05%
5	Streetlights	0.22087	0.22048	-0.18%	0.11279	0.11249	-0.27%
6	Standby	0.14808	0.14644	-1.11%	0.07727	0.07576	-1.96%
7	Agriculture	0.18154	0.18231	0.43%	0.13689	0.13916	1.66%
8	E-20 T	0.11395	0.11434	0.34%	0.03420	0.03465	1.33%
9	E-20 P	0.14847	0.14879	0.21%	0.06957	0.06950	-0.10%
10	E-20 S	0.16582	0.16563	-0.11%	0.07267	0.07235	-0.45%
11	Total	$0.18697	$0.18683	-0.08%	$0.09093	$0.09151	0.64%

While PG&E is not proposing to adjust the allocation of generation and distribution in this proceeding, PG&E has prepared a full cost of service showing. For the full cost of service showing, the standard TOU periods[15] were applied across all customer classes to determine the cost to serve each customer class. Table A of Attachment 1 to this chapter illustrates the revenue allocation results at full cost using the Rental Method for marginal customer access costs (MCAC) recommended by PG&E in this proceeding. Table B of Attachment 1 to this chapter illustrates the revenue allocation results at full cost using the new-customer only method for MCAC recommended by PG&E in prior cases.

E. Implementation of Rate Changes

The total rate levels PG&E will implement as a result of a final decision in this proceeding will depend on the revenue allocation and rate design methods approved in this proceeding, as well as revenue requirements adopted by the CPUC or FERC in other proceedings. Illustrative rates provided in this exhibit are based on revenues collected by current rates (effective October 1, 2016) using forecasted 2017 billing determinants. As a result, the illustrative revenues do not include any forecast of future revenue requirement changes and are not based on the sales forecasts that will actually be used to set rates.

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15 See Exhibit (PG&E-9), Chapter 12.

In this section, PG&E describes its proposal to implement rates resulting from this proceeding as well as its proposal to implement rates arising from future revenue requirement changes.

1. Implementing GRC Phase II Rate Changes

If PG&E's proposal is approved, the initial rate change resulting from a decision in this proceeding would only incorporate the changes to PPP rates described above, as well as any changes to streetlight facility rates and customer charges. If the rate change pursuant to a final decision in this Phase II proceeding occurs in 2017, it shall be based on the sales forecast utilized in the 2017 Energy Resource Recovery Account forecast proceeding. If the rate change pursuant to a final decision in this Phase II proceeding is not implemented until January 1, 2018, the rate change on January 1, 2018, would be conducted in two steps: (1) allocation pursuant to the Phase II decision based on the 2017 sales forecast; and then (2) allocation of revised revenue requirements pursuant to the 2018 AET, based on the 2018 sales forecast and the guidelines set forth below, regarding Implementing Revenue Requirement Changes. If the rate change made pursuant to a final decision in this Phase II proceeding does not occur until after January 1, 2018, PG&E would incorporate the Phase II requirements into rates based on then-current rates and the 2018 sales forecast.

Some rate changes, either proposed by PG&E or ultimately approved by the Commission, go beyond a simple change to a rate value and may require either a structural change to PG&E's billing system and/or an extended period of education for PG&E employees and customers. Such changes will be implemented by PG&E diligently, and as rapidly as possible consistent with other workflow demands as well as smooth operations of the systems involved, while allowing time for adequate customer outreach and education.

PG&E expects that non-residential rate schedules with new TOU periods would be rolled out to customers as they become available subsequent to the initial Phase II rate change. Timing for other initiatives, such as changes to baseline quantities, are described in the following chapters.

2. Implementing Revenue Requirement Changes

In general, PG&E proposes to continue the existing practices for rate changes to implement revenue requirement changes as adopted in D.15-08-005. PG&E's proposed guidelines are set forth in Attachment 2 of this chapter, and would apply unless specifically addressed in each rate design chapter. While not universally applied, PG&E has made two notable changes. First, in the past, PG&E has generally not revised customer charges between GRCs. In this proceeding PG&E proposes to revise the level of the customer charge with the level of distribution demand and energy charges when distribution revenue changes between GRCs. Second, in many cases, PG&E proposes to hold rate differentials between TOU periods the same in order to preserve the marginal cost price differential when revenue requirements change between GRCs. These practices will be used to adjust rates for revenue requirement changes following a decision in this proceeding.

F. Additional Proposals

The following additional issues are unique in nature or common to most rate design classes and are included here to avoid the need to duplicate the discussion for each applicable rate design class.

1. Residential Customer Charge

PG&E is required to file its proposal for default/opt-out TOU rates for the residential class in a 2018 Rate Design Window (RDW) proceeding to be filed on January 1, 2018. That filing may also include a proposal for a residential customer charge. After a decision is issued approving default TOU rates and a fixed customer charge in the 2018 RDW and eligible residential customers are defaulted to TOU, the utilities may file to implement the adopted fixed customer charge for all residential customers.[16] To that end, the Commission has directed that consideration of the categories of costs to be included in a residential customer charge, as well as the methodology to be used to derive the customer charge, be considered in this proceeding. PG&E has included as Appendix F to Exhibit (PG&E-9) its report on the residential fixed customer charge.

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16 D.15-07-001, mimeo, p. 193.

2. Dynamic Pricing

In this proceeding, PG&E proposes to revise the PDP event hours for non-residential customers to 5 p.m. to 9 p.m. to be consistent with the later timeframes for peak adjusted net load.[17] The change to PDP event hours would occur when the new TOU periods for non-residential customers become mandatory. In the interim, PG&E proposes to retain the current PDP charges and terms of operation and to continue the current annual revenue adjustments for revenue neutrality and for PDP bill protection and number of operations relative to the design basis. PG&E expects that revised PDP charges and revenue neutral rate adjustments will be required with the new event period, based on the final rates adopted in this proceeding. Accordingly, PG&E proposes to file a Tier 2 advice letter after a decision is rendered in this proceeding with revised PDP rates.

For the residential SmartRate™ Program, PG&E proposes to retain the current event hours (currently 2 p.m. to 7 p.m.) at this time. PG&E will propose revised SmartRate event hours as part of the 2018 RDW proceeding. In this proceeding, PG&E proposes to retain the current SmartRate event charge and to begin annual revenue neutral adjustments for SmartRate to maintain revenue neutrality between the event charge and the SmartRate Non-High-Price Period Credit. In addition, PG&E proposes to retain the current terms of operation and retain adjustments for the participation credit as well as bill protection.

3. Mandatory Transition to TOU Schedules

In accordance with D.10-02-032, as modified by D.11-11-008, PG&E is required to transition bundled small and medium sized agricultural customers, and bundled small and medium sized commercial customers, to TOU rates (those customers less than 200 kW in size). As discussed further below, PG&E requests that DA/CCA customers with 12 months of interval data also be transitioned off non-TOU rates in order to allow PG&E to eliminate the non-TOU versions of the rates.

For bundled commercial customers on Schedules A-1 and A-10, mandatory TOU required transition to the TOU version of each rate

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17 See Exhibit (PG&E-9), Chapter 12 where revised event hours are recommended.

schedule began November 1, 2012. Since the distribution rates on the destination TOU schedule were the same as distribution rates on the non-TOU rate, transfer of DA/CCA customers to TOU rates would have had no net effect on the portion the charges paid by these customers to the utility (i.e., the utility charges). PG&E requests in this proceeding to transfer these customers to the TOU version of the rate, contingent upon availability of 12 months of interval data, so that the non-TOU version of the rate can be eliminated. PG&E notes that, as was the case previously, these commercial DA/CCA customers will receive no change in utility charges in making the transition to the TOU version of their current rate.

Small and medium sized bundled agricultural customers taking service on non-TOU Schedule AG-1 began making a transition to mandatory TOU rates beginning March 1, 2013. Unlike commercial schedules, the distribution rates are different between Schedule AG-1 and the TOU destination rate schedules. For example, distribution rates on Schedule AG-1 typically vary seasonally, while the distribution rates on agricultural TOU rates may vary either by TOU period or by season but at different levels than the non-TOU rates. In this proceeding, PG&E requests that it be allowed to transition agricultural DA/CCA customers with 12 months of interval data to TOU rate schedules on a mandatory basis. PG&E would then eliminate non-TOU Schedule AG-1.

4. PCIA Exemption for Medical Baseline Customers

Currently, DA/CCA customers that receive a medical baseline allowance also receive an exemption from paying the PCIA. In this proceeding, PG&E proposes to eliminate that exemption as it has also been eliminated for CARE customers.

<u>Background</u>

On June 19, 2003, the Commission issued Resolution E-3813 regarding the DA Cost Responsibility Surcharge (CRS) which included the DWR Power Charge, the DWR Bond Charge and CTC. Resolution E-3813 exempted CARE and Medical Baseline customers from all components of the CRS except CTC. As a result, PG&E’s Schedule DA CRS was established with these same exemptions.

In 2005, Schedule CCA-CRS was created for CCA customers as a result of D.04-12-046. Like Schedule DA-CRS, Schedule CCA-CRS exempted both CARE and medical baseline customer from the DWR Bond and Power Charge portions of the CCA CRS. In D.05-12-041, the Commission stated that the CARE discount should be provided as a reduction to distribution rates. The decision further indicated that CRS should not be discounted.[18]

In 2006, as a result of D.06-07-030, the DWR Power Charge component of the DA CRS was replaced with the PCIA. PG&E modified Schedules DA CRS and CCA CRS to specify that CARE and medical baseline customers were exempt from the PCIA. In March 2006, PG&E filed its Application in Phase II of the 2007 GRC. Pursuant to D.05-12-041, PG&E proposed to apply the CARE discount to only distribution rates and reduce distribution rates applicable to CARE customers (i.e., increasing the discount), and to charge CARE customers for the PCIA (at that time the DWR Power Charge component of the CRS).

In D.07-09-004, the Commission adopted a settlement approving PG&E's proposal. PG&E filed tariffs effective January 2008, in which text for both Schedules DA CRS and CCA CRS were revised to delete the exemption to the PCIA for CARE customers. Medical baseline customers retained the exemption for the PCIA because the discussion in D.05-12-041 was specific to CARE and the manner in which the CARE discount was managed. PG&E has maintained an exemption for medical customers to the PCIA since then.

Proposal

In D.05-12-041, the Commission adopted a key concept with regard to CARE rates. Specifically, DA/CCA customers should receive the same CARE discount as bundled customers, provided DA/CCA customers fund the CARE discount the same as bundled customers. By providing the CARE discount through distribution rates, the Commission fully ensured that CARE DA/CCA customers were receiving the same CARE discount as bundled CARE customers. Further, by ending the PCIA exemption for

[18] D.05-12-041, mimeo, p. 50, 51.

CARE customers, the Commission ensured that DA/CCA customers were not receiving a discount in excess of the bundled CARE discount.

In this proceeding, PG&E requests the same treatment for medical baseline customers. In Attachment 3, PG&E shows an example of billing for the same customer under four different rate options: (1) Schedule E-1 non-medical; (2) Schedule E-1 medical; (3) Schedule E-1 CARE; and (4) Schedule E-1 CARE and medical. Consistent with PG&E's current (i.e., June 1, 2016) tariffs, the discount for medical is applied to distribution and CIA rates for all customers. However, DA/CCA customers that receive a medical allowance also receive an exemption from the PCIA. In the case of both medical examples, the discount is higher for DA/CCA customers by the amount of the PCIA. This added discount for DA/CCA customers is inequitable and inappropriate. Instead, any benefit received by medical customers should be provided equally to bundled and DA/CCA customers and funded through rates paid by both bundled and DA/CCA customers. The current asymmetric discounting should not be allowed. In this proceeding, PG&E requests that the Commission equalize the discounts between bundled and DA/CCA medical baseline customers by eliminating the PCIA exemption for DA/CCA medical baseline customers.

5. Real Time Pricing

In this proceeding, PG&E requests recovery of its incremental expenses to develop Real-Time Pricing (RTP). As discussed in greater detail below, the CPUC directed PG&E to develop and file a proposal for RTP and later closed the proceeding where the request was made without action on the RTP proposal, effectively cancelling the project. PG&E filed Advice Letter 4641-E to recover the incremental costs for developing the RTP proposal. In response, the Commission directed PG&E to seek recovery in a rate design proceeding should it still wish to recover these costs. Accordingly, PG&E seeks recovery of $505,070, plus interest, of RTP development costs in this proceeding. If approved, these funds would be transferred from the Dynamic Pricing Memorandum Account (DPMA) to the Distribution Revenue Adjustment Mechanism (DRAM) for recovery in rates.

<u>Background</u>

To establish a process to address the details of RTP, in D.08-07-045 the Commission ordered PG&E to file a proposal for RTP in its next GRC Phase II proceeding. Specifically, Ordering Paragraph (OP) 7 of that decision provides PG&E shall propose optional RTP rates for all customer classes as part of its 2011 GRC Phase II to be filed on March 1, 2010. *The effective date of the proposed rates shall be on or before May 1, 2011.* (emphasis added.) In addition, in accordance with OP 15 of D.08-07-045, PG&E received authorization to establish the DPMA to record development and implementation costs associated with dynamic pricing ordered by that decision, including an RTP option. Under the rate case plan, a final decision in GRC Phase II could have been as early as April 2011, leaving only one month to fully implement the RTP program. Given this compressed timeframe, PG&E began planning and development activities and recorded the costs of those activities to the DPMA in order to be in a position to comply with a May 1, 2011 effective date. On March 22, 2010, PG&E filed a proposal for an optional RTP program in its 2011 GRC Phase II proceeding (Application (A.) 10-03-014), including a request to recover the cost of implementing the program as allowed by D.08-07-045 (see OP 14). PG&E's request for cost recovery was approximately $17 million, including cost recovery of project development costs incurred during 2009 and 2010 (A.10-03-014, Exhibit (PG&E-3), Dynamic Pricing and Revised Customer Energy Statement, Table 11-2, page 11-7).

In developing the proposal and cost estimate for RTP, and ultimately as described in its testimony in A.10-03-014, PG&E recognized that given the complexity of a RTP rate, the limited specific guidance on RTP included in D.08-07-045, and the pressure of other large scale billing system improvements already planned or underway in 2010 and 2011, it would be better to wait for a final decision on the structure of RTP before going farther with implementation of the RTP project. Accordingly, concurrent with filing A.10-03-014, PG&E filed a Petition to Modify D.08-07-045 requesting a delay in implementation of the RTP project until approximately one year after the final decision in that proceeding. In D.10-07-008, the Commission approved PG&E's request.

On March 3, 2011, in an ALJ Ruling Granting Motion to Revise Schedule for Phase 3 of A.10-03-014, RTP issues were deferred pending further notice. No further action was taken by the Commission on PG&E's proposal. The Commission issued D.14-03-002 which, among other things, closed A.10-03-014. As a result, this project has been cancelled. PG&E incurred $505,070, plus accrued interest, in developing its RTP proposal in reliance on the Commission's directives which indicated that the RTP option should be implemented at the earliest possible time.

Proposal

In Advice Letter 4641-E, dated May 13, 2015, PG&E requested recovery of the expenses incurred for RTP. In response, on September 29, 2015, by letter from the Director of the Energy Division, the Commission dismissed PG&E's request indicating that the request for recovery should be made in a rate design proceeding. Accordingly, in this Phase II proceeding, PG&E requests that the expenditures incurred for the initial planning and development of the RTP rate option be transferred from the DPMA to DRAM for recovery.

6. Discount for Food Banks

Pub. Util. Code Section 739.3 requires that the Commission establish a program of rate assistance to eligible food banks at a fixed percentage to be determined by the Commission. Section 739.3 also leaves the funding source for the rate assistance program subject to approval by the Commission. In this proceeding, PG&E proposes to expand the applicability for CARE rates for non-residential customers to qualified food banks.

The applicable schedule for electric service is Schedule E-CARE. Schedule E-CARE provides rate discounts for qualified commercial customers based on the percentage discount applicable for residential CARE customers. This fixed percentage discount is targeted to reach a level of 30 to 35 percent in compliance with D.15-07-001 and Assembly Bill (AB) 327.[19] PG&E applies the Schedule E-CARE discount to eligible

[19] D.15-07-001, mimeo, p. 231.

customers on a cents per kWh basis.[20] The discount is available to eligible bundled, DA and CCA customers and will be applied to the distribution rate component. Like the CARE program, PG&E proposes that the amount of the discount be funded via the CARE surcharge component of the PPP rate on an equal cents per kWh basis.

Similarly, PG&E proposes to use Schedule G-CARE for gas service to eligible food banks. Schedule G-CARE provides a 20 percent discount on the charges billed under the otherwise applicable rate schedule. For the purpose of calculating the G-CARE bill, the otherwise applicable commodity or volumetric charge will be the adopted charge, less the PPP-CARE rate component. Core transport eligible customers receiving service in conjunction with Schedule G-CT will receive a 20 percent discount on the transportation charges billed under their otherwise-applicable rate schedule. They will receive an additional 20 percent discount on the procurement charge for their otherwise applicable rate schedule. This to assure that the customer receives the same discount whether they are procuring gas from PG&E or from another party. Again, like the CARE program, PG&E further proposes that the amount of the discount be funded via the CARE surcharge component of the PPP rate on an equal cents per kWh basis.

G. Organization of the Exhibit

Exhibit (PG&E-4) has a total of 11 chapters. The remainder of this exhibit is organized as follows:

- Chapter 2 – Describes the calculation of marginal cost revenue.
- Chapter 3 – Describes the revenue allocation methods used or proposed for each of PG&E's functional revenues.
- Chapter 4 – Sets forth PG&E's residential class rate design proposals.
- Chapter 5 – Sets forth PG&E's small light and power class rate design proposals.

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20 PG&E notes that Section 739.3(a) requires "a program of rate assistance to eligible food banks at a fixed percentage to be determined by the commission." PG&E believes that even though Schedule E-CARE is applied on a cents per kWh basis, it is based on a fixed percentage as required by AB 327, and is therefore fully compliant with the requirements for a discount to food banks.

- Chapter 6 – Sets forth PG&E's medium and large light and power class rate design proposals.
- Chapter 7 – Sets forth PG&E's agricultural class rate design proposals.
- Chapter 8 – Sets forth PG&E's streetlight class rate design proposals.
- Chapter 9 – Sets forth PG&E's standby class rate design proposals.
- Chapter 10 – Describes customer research and proposals for implementation of new non-residential TOU period rates.
- Chapter 11 – Sets forth PG&E's proposals for continuation of economic development rates.

The following appendices are also provided with this exhibit.

- Appendix A – Sets forth illustrative proposed revenue allocation.
- Appendix B – Sets forth present and proposed illustrative rates.
- Appendix C – Sets forth PG&E's study of relevant and appropriate demand charge rates.
- Appendix D – Sets forth PG&E's study of the small and medium customer class demand threshold.
- Appendix E – Sets forth the report on the Agricultural Rate Design Collaborative Process.
- Appendix F – Sets forth the report on the need for an Agricultural Balancing Account.
- Appendix G – Sets forth bill impact reports for PG&E's rate design proposals.
- Appendix H – Sets forth PG&E's customer survey regarding TOU periods.
- Appendix I – Sets forth a table of compliance items.

Exhibit (PG&E-9) presents PG&E's marginal cost proposal. The chapters in Exhibit (PG&E-9) describe in detail the methodologies used to estimate marginal cost, and present the resulting unit marginal cost estimates.

Exhibit (PG&E-3) sets forth the statements of qualifications for the witnesses sponsoring testimony in this proceeding.

H. Conclusion

In this chapter, PG&E has discussed the general policy objectives that underlie its proposals, including continuing to make progress towards rates that are economically efficient, cost-based and promote equity among customers, as balanced with other objectives. PG&E has also summarized its revenue allocation proposal and its proposed guidelines for designing rates in this proceeding. In addition, this chapter includes PG&E's proposals to set rates for future revenue requirement changes. Finally, PG&E reviews several rate-related issues and, where appropriate, has asked the Commission to approve PG&E's proposed recommendation. PG&E respectfully requests approval of its proposals in this proceeding.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT A
FULL COST REVENUE ALLOCATION RESULTS

TABLE 1A-1
FULL COST REVENUE ALLOCATION RESULTS USING THE RENTAL METHOD FOR MARGINAL CUSTOMER ACCESS COST
(PRESENT RATES EFFECTIVE OCTOBER 1, 2016)

		Bundled Average Change			DA/CCA Average Change		
Line No.	Customer Class	Present Rate	Proposed Rate	Change	Present Rate	Proposed Rate	Change
1	Residential Total	0.19733	0.19229	-2.6%	0.14596	0.14137	-3.1%
2	Small Light and Power	0.22643	0.24945	10.2%	0.15546	0.18453	18.7%
3	A-10	0.20027	0.19026	-5.0%	0.10839	0.10953	1.1%
4	E-19	0.17536	0.16540	-5.7%	0.08575	0.07960	-7.2%
5	Streetlights	0.22087	0.34179	54.7%	0.11279	0.22532	99.8%
6	Standby	0.14808	0.14793	-0.1%	0.07727	0.06874	-11.1%
7	Agriculture	0.18154	0.21040	15.9%	0.13689	0.15947	16.5%
8	E-20 T	0.11379	0.11676	2.6%	0.03419	0.03322	-2.9%
9	E-20 P	0.14847	0.14100	-5.0%	0.06957	0.06220	-10.6%
10	E-20 S	0.16582	0.15450	-6.8%	0.07267	0.06261	-13.9%
11	Total	$0.18696	$0.18740	0.2%	$0.09093	$0.08926	-1.8%

TABLE 1A-2
FULL COST REVENUE ALLOCATION RESULTS USING THE NEW CUSTOMER ONLY (NCO) METHODOLOGY FOR MARGINAL CUSTOMER ACCESS COST
(PRESENT RATES EFFECTIVE OCTOBER 1, 2016)

		Bundled Average Change			DA/CCA Average Change		
Line No.	Customer Class	Present Rate	Proposed Rate	Change	Present Rate	Proposed Rate	Change
1	Residential Total	0.19733	0.18874	-4.4%	0.14596	0.13733	-5.9%
2	Small Light and Power	0.22643	0.23225	2.6%	0.15546	0.16799	8.1%
3	A-10	0.20027	0.18659	-6.8%	0.10839	0.10591	-2.3%
4	E-19	0.17536	0.16822	-4.1%	0.08575	0.08199	-4.4%
5	Streetlights	0.22087	0.31470	42.5%	0.11279	0.19823	75.8%
6	Standby	0.14808	0.15165	2.4%	0.07727	0.07136	-7.7%
7	Agriculture	0.18154	0.24060	32.5%	0.13689	0.18062	31.9%
8	E-20 T	0.11380	0.11664	2.5%	0.03419	0.03310	-3.2%
9	E-20 P	0.14847	0.14738	-0.7%	0.06957	0.06837	-1.7%
10	E-20 S	0.16582	0.16240	-2.1%	0.07267	0.06933	-4.6%
11	Total	$0.18696	$0.18743	0.3%	$0.09093	$0.08915	-2.0%

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT B
RATE DESIGN GUIDELINES TO IMPLEMENT REVENUE REQUIREMENT CHANGES

The following guidelines will be applied to changing rates for revenue requirement changes subsequent to the decision in the Pacific Gas and Electric Company's (PG&E) 2017 General Rate Case (GRC) Phase II proceeding.

a. Revenue requirement changes will be identified by function (e.g., nuclear decommissioning, generation, etc.). Each customer class and schedule will be allocated the average percentage change in functional revenue necessary to collect the functional revenue requirement. This approach to allocating costs using a system average percentage change by function will be employed such that each customer group's share of each functional revenue requirement remains approximately the same. For schedules that are designed together, such as schedules that are designed on a revenue neutral basis, the system average percentage change by function will be applied to the combined rate design group.

b. Generation revenue developed to determine the appropriate starting point to apply the percentages from Section (a) above will exclude directly assigned revenue (i.e., other standby revenue). For the rate changes where there is a change to CTC, current generation revenue used for purposes of allocation will be determined after the change to CTC is incorporated, consistent with current practice.[1]

c. CTC will be allocated based on the 100 peak hour allocation method. 100 peak hour allocation factors for CTC will be revised each year based on the most recent available information at the time PG&E files its annual ERRA forecast application consistent with current practice. The NSGC and, for DA/CCA customers, the PCIA will be developed consistent with current practice.

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1 In addition, generation adjustments for SmartRate™ and Peak Day Pricing will be deducted from the generation revenue to be allocated as approved by the California Public Utilities Commission (CPUC or Commission).

d. Distribution revenue (including the Conservation Incentive Adjustment) developed to determine the appropriate starting point to apply the percentages from Section (a) above will exclude directly assigned revenue (including, but not limited to, other standby revenue, E-BIP discounts, streetlight facilities charges, meter charges, employee discounts, and the Schedule A-15 facilities charge) as well as estimated California Alternate Rates for Energy (CARE) Program discounts.

e. PPP rates will be developed as the sum of three pieces and will be allocated as follows:

   1. The cost of the CARE Program will be determined and the CARE surcharge will be set once per year in the Annual Electric True-Up (AET) proceeding based on the difference between CARE and non-CARE rates excluding the CARE surcharge and the Department of Water Resources (DWR) Bond charge. The cost will be allocated to eligible customers on an equal cents per kilowatt-hour (kWh) basis and collected through the CARE surcharge component of PPP rates.

   2. The cost of the ESA, Procurement EE, EPIC and PGC-EE will be allocated to customers based on an equal percent of the sum of then-required revenue for these programs (that is, the same percentage will be applied to the then-required revenue for each customer group to determine the allocated revenue).

f. Rate design for residential rate changes between GRCs will be dictated by the Commission's decision in the RROIR (D.15-07-001), or its successor.

g. Non-residential rate changes will be implemented as equal percentage changes to customer, demand and energy charges by component as necessary to collect the assigned revenue, unless otherwise addressed in the rate design for specific schedules. Streetlight facilities charges, meter charges, and minimum charges will be unchanged between general rate cases,[2] unless otherwise specified in a Commission decision in this GRC Phase II, or revised by a separate decision (for example, in a PG&E Rate Design Window proceeding).

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[2] All customer charges on non-residential rate schedules will be revised with demand and energy charges when changes to distribution rates are required, unless specifically exempted from change in rate design testimony.

h. The DWR Bond charge, the Energy Cost Recovery Amount and Nuclear Decommissioning charge shall continue to be collected on an equal cents per kWh basis for all eligible customers.

i. Transmission Owner and other Federal Energy Regulatory Commission (FERC) jurisdictional rates shall be set by the FERC.

j. Greenhouse gas allowance returns will be set as specified separately by the CPUC.

k. PG&E will continue to make directly assigned adjustments for the Distribution Bypass Deferral Rate Memorandum Account in its AET filings. PG&E will continue the practices for discount recovery approved via approval of Advice Letter 3524-E.

l. The costs of the Family Electric Rate Assistance program will continue to be assigned to the residential class.

m. Should the Commission approve an entirely new revenue requirement category to be included in rates between the effective dates of the 2017 GRC Phase II and the 2020 GRC Phase II decisions, the revenue allocation and rate design for that new revenue requirement category should be decided by the Commission at that time and the rules governing existing revenue requirement categories will not govern or be precedential for that purpose.

n. The CPUC Fee revenue requirement will be allocated on an equal cents per kWh basis and collected in distribution rates.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT C
PICA EXEMPTION FOR MEDICAL BASELINE CUSTOMERS

TABLE 1C-1
(NON-CARE)

Line No.			E1 Non-Medical				E1 Medical			
1	Basic X	BL Quantitiy	Summer		10.1		Summer		26.5	
2		Usage			700				700	
3		Days			30				30	
4	Usage	Tier 1			303				700	
5	Usage	Tier 2			303				0	
6	Usage	Tier 3			94				0	
7	Medical		BL Adder		0		BL Adder		1	
			Bundled Rate	Charge	DA/CCA Rate	DA/CCA Charge	Bundled Rate	Charge	DA/CCA Rate	Charge
8	Generation		0.09684	$ 67.79			0.09684	$ 67.79		
9	Distribution		0.08334	$ 58.34	0.08334	$ 58.34	0.08334	$ 58.34	0.08334	$ 58.34
10	CIA	Tier 1	-0.04562	$ (13.82)	(0.04562)	$ (13.82)	-0.04023	$ (28.16)	(0.04023)	$ (28.16)
11		Tier 2	0.01361	$ 4.12	0.01361	$ 4.12	0.01900	$ -	0.01900	$ -
12		Tier 3	0.17392	$ 16.35	0.17392	$ 16.35	0.13931	$ -	0.13931	$ -
13	Transmission		0.01883	$ 13.18	0.01883	$ 13.18	0.01883	$ 13.18	0.01883	$ 13.18
14	TRA		0.00434	$ 3.04	0.00434	$ 3.04	0.00434	$ 3.04	0.00434	$ 3.04
15	RS		0.00023	$ 0.16	0.00023	$ 0.16	0.00023	$ 0.16	0.00023	$ 0.16
16	PPP		0.01405	$ 9.84	0.01405	$ 9.84	0.01405	$ 9.84	0.01405	$ 9.84
17	ND		0.00022	$ 0.15	0.00022	$ 0.15	0.00022	$ 0.15	0.00022	$ 0.15
18	CTC		0.00338	$ 2.37	0.00338	$ 2.37	0.00338	$ 2.37	0.00338	$ 2.37
19	ECRA		-0.00002	$ (0.01)	(0.00002)	$ (0.01)	-0.00002	$ (0.01)	(0.00002)	$ (0.01)
20	DWR Bond		0.00539	$ 3.77	0.00539	$ 3.77				
21	NSGC		0.00255	$ 1.79	0.00255	$ 1.79	0.00255	$ 1.79	0.00255	$ 1.79
22	2012 PCIA				0.02363	$ 16.54				
23	2012 EFFS				0.00061	$ 0.43			0.00061	$ 0.43
24	Total T1		0.18353	$ 55.61	0.11093	$ 33.61	0.18353	$ 128.47	0.08730	$ 61.11
25	Total T2		0.24276	$ 73.56	0.17016	$ 51.56	0.24276	$ -	0.14653	$ -
26	Total T3		0.40307	$ 37.89	0.33047	$ 31.06	0.36307	$ -	0.26684	$ -
27	Unbundle check			$ 167.05		$ 116.23		$ 128.47		$ 61.11
28	Total check			$ 167.05		$ 116.23		$ 128.47		$ 61.11
								Bundled		**DA/CCA**
29	Medical Discount							$ 38.58		$ 55.12
30	CARE Discount							$ 65.13		$ 65.13
31	Medical and CARE discount							$ 82.88		$ 99.42
	Rates Effective October 1, 2016									

TABLE 1C-2
(CARE)

Line No.		E1 CARE Non-Medical				E1 CARE Medical			
1	Tier 1			303				700	
2	Tier 2			303				0	
3	Tier 3			94				0	
		Bundled Rate	Charge	DA/CCA Rate	Charge	Bundled Rate	Charge	DA/CCA Rate	Charge
4	Generation	0.09684	$ 67.79			0.09684	$ 67.79		
5	Distribution	0.01228	$ 8.60	0.01228	$ 8.60	0.01228	$ 8.60	0.01228	$ 8.60
6	CIA Tier 1	-0.02548	$ (7.72)	(0.02548)	$ (7.72)	-0.02548	$ (17.84)	(0.02548)	$ (17.84)
7	Tier 2	0.00266	$ 0.81	0.00266	$ 0.81	0.00266	$ -	0.00266	$ -
8	Tier 3	0.07264	$ 6.83	0.07264	$ 6.83	0.07264	$ -	0.07264	$ -
9	Transmission	0.01883	$ 13.18	0.01883	$ 13.18	0.01883	$ 13.18	0.01883	$ 13.18
10	TRA	0.00434	$ 3.04	0.00434	$ 3.04	0.00434	$ 3.04	0.00434	$ 3.04
11	RS	0.00023	$ 0.16	0.00023	$ 0.16	0.00023	$ 0.16	0.00023	$ 0.16
12	PPP	0.00708	$ 4.96	0.00708	$ 4.96	0.00708	$ 4.96	0.00708	$ 4.96
13	ND	0.00022	$ 0.15	0.00022	$ 0.15	0.00022	$ 0.15	0.00022	$ 0.15
14	CTC	0.00338	$ 2.37	0.00338	$ 2.37	0.00338	$ 2.37	0.00338	$ 2.37
15	ECRA	-0.00002	$ (0.01)	(0.00002)	$ (0.01)	-0.00002	$ (0.01)	(0.00002)	$ (0.01)
16	NSGC	0.00255	$ 1.79	0.00255	$ 1.79	0.00255	$ 1.79	0.00255	$ 1.79
17	2012 PCIA			0.02363	$ 16.54				
18	2012 EFFS			0.00061	$ 0.43			0.00061	$ 0.43
19	Total T1	0.12025	$ 36.44	0.04765	$ 14.44	0.12025	$ 84.18	0.02402	$ 16.81
20	Total T2	0.14839	$ 44.96	0.07579	$ 22.96	0.14839	$ -	0.05216	$ -
21	Total T3	0.21837	$ 20.53	0.14577	$ 13.70	0.21837	$ -	0.12214	$ -
22	Unbundle check		$ 101.92		$ 51.10		$ 84.18		$ 16.81
23	Total check		$ 101.92		$ 51.10		$ 84.18		$ 16.81
	Rates Effective October 1, 2016								

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

CALCULATION OF MARGINAL COST REVENUE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
CALCULATION OF MARGINAL COST REVENUE

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
CALCULATION OF MARGINAL COST REVENUE

A. Introduction

In this chapter, PG&E presents a description of the development of the marginal cost revenues traditionally used in PG&E's Equal Percent of Marginal Cost (EPMC) allocation of the distribution and generation functional revenue. As detailed in Chapter 1, "Revenue Allocation and Rate Design Policy," there are already many proposed changes in rate design and Time-of-Use (TOU) period and season definition that customers will be experiencing over the next several years. As a result, PG&E believes it is appropriate not to change the allocation to distribution and generation revenue requirements in this application. Accordingly, PG&E has developed marginal costs for use in illustrative full cost of service allocations, but is only proposing the use of the marginal cost revenues developed in this chapter for the purposes of rate design.

B. Distribution Marginal Cost Revenue

1. Demand-Related Distribution Marginal Cost Revenue

Demand-related distribution marginal costs are estimated for PG&E's primary distribution (between 60 kilovolts (kV) and 4 kV) and secondary distribution (below 4 kV) systems. PG&E uses the appropriate demand measure for each marginal cost to compute the marginal cost revenue. Specifically, PG&E estimates class loads at the substation level using weighting factors called "peak capacity allocation factors" (distribution

PCAF)[1] and at the final line transformer (FLT) level.[2]

a. Primary Marginal Cost Revenue

PG&E uses division level distribution PCAF-weighted loads to estimate primary marginal cost revenue. For a given rate schedule and division, the recorded primary marginal cost revenue equals a single year of recorded division-level distribution PCAF loads multiplied by the estimated primary marginal cost and the applicable loss factors. The total recorded primary marginal cost revenue for the schedule equals the sum of the recorded primary marginal cost revenues across all divisions. Once the recorded primary marginal cost revenue is calculated by schedule, PG&E divides the recorded primary marginal cost revenue by each class' recorded sales to determine primary marginal cost revenue per kWh.

Each class' test-year primary marginal cost revenue equals the class' primary marginal cost revenue per kWh multiplied by the class' forecast 2017 sales.

b. New Business Primary Marginal Cost Revenue

As described in Exhibit (PG&E-9), Chapter 6, "Marginal Distribution Capacity Costs," new business primary marginal costs are associated with investments made to extend distribution to, and provide capacity for new customers. PG&E calculates the new business primary marginal cost revenue based on FLT demands.

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1 Additional information on distribution PCAF loads is provided in the Marginal Cost testimony, Exhibit (PG&E-9), Chapter 10. These PCAF-weighted loads are then summarized by division for the calculation of primary demand-related marginal cost revenue.

2 Additional information on FLT loads is provided in the Marginal Cost testimony, Chapter 11 of Exhibit (PG&E-9). FLT loads are either the class' diversified non-coincident demand at the FLT (residential and small commercial classes) or the class' undiversified non-coincident demand at the FLT (all other classes). Non-coincident demand is the class' highest observed demand during the year. As more than one residential or small commercial customer are served by a FLT, the FLT loads for these classes are scaled down (diversified) to reflect the fact that not all the customers served by that transformer will be operating at the time the FLT reaches its peak. For all the other classes, PG&E assumes that there is one customer per FLT.

The method for calculating the new business primary marginal cost revenues is similar to that described for the primary marginal cost revenues. PG&E multiplies a single year of each schedule’s recorded division-specific FLT loads by the estimated new business primary marginal costs for that division from Exhibit (PG&E-9), Chapter 6, “Marginal Distribution Capacity Costs,” to get division-specific recorded new business primary marginal cost revenue by schedule. PG&E then sums each schedule’s recorded new business primary marginal cost revenues across all divisions to obtain total recorded new business primary marginal cost revenue by schedule and divides by recorded sales to calculate the new business primary marginal cost revenue per kWh for each schedule. Each class’ test year (TY) new business primary marginal cost revenue equals the class’ new business primary marginal cost revenue per kWh multiplied by the class’ forecast 2017 sales.

c. Secondary Marginal Cost Revenue

Secondary marginal costs are associated with load growth only as explained in Exhibit (PG&E-9), Chapter 6, “Marginal Distribution Capacity Costs.” PG&E calculates the secondary marginal cost revenue based on FLT demands.

The method for calculating the secondary marginal cost revenues is similar to that described for the new business primary marginal cost revenues. PG&E multiplies a single year of each schedule’s recorded division-specific FLT loads by the estimated secondary marginal costs for that division from Exhibit (PG&E-9), Chapter 6, “Marginal Distribution Capacity Costs,” to get division-specific recorded secondary marginal cost revenue by schedule. PG&E then sums each schedule’s recorded secondary marginal cost revenues across all divisions to obtain total recorded secondary marginal cost revenue by schedule and divides by recorded sales to calculate the secondary marginal cost revenue per kilowatt-hour (kWh) for each schedule.

Each class’ TY secondary marginal cost revenue equals the class’ secondary marginal cost revenue per kWh multiplied by the class’ forecast 2017 sales.

2. Standby Class Demand-Related Distribution Marginal Cost Revenue

In order to assign distribution demand-related marginal cost revenue to the standby class equitably, PG&E utilizes the otherwise applicable rate schedules' (OAS) test-year distribution demand-related marginal cost revenue.

For primary, new business primary, and secondary marginal costs, PG&E calculates the TY dollar per kW marginal cost for the standby customers' OAS by dividing the TY marginal cost revenues by the schedule's TY demand. The standby demand-related marginal cost revenue equals the OAS dollar per kW marginal cost revenue multiplied by 85 percent of the contract capacity. The 85 percent adjustment factor accounts for the relationship between contract capacity (as used to assess standby charges) and average monthly maximum demands (as used in rate design for the OAS).

This approach assigns the level of distribution system diversity to the standby class that would be assigned to the class if generation had not been installed.

3. Marginal Customer Cost Revenue

The marginal customer access costs are summarized in Exhibit (PG&E-9), Chapter 7, "Marginal Customer Access Costs." The customer forecast is a monthly forecast of customers (or billings) which, when summed across the year, is referred to as customer-months.

Each class' marginal customer cost revenue for the TY equals the class' marginal customer cost multiplied by the forecast number of customer-months divided by 12.

C. Marginal Generation Cost Revenue

1. Marginal Generation Capacity Cost Revenue

Marginal generation capacity costs represent the cost to serve an additional kW of demand expressed in dollars per kW year and vary by service voltage. PG&E proposes to calculate the marginal generation capacity cost revenue using system PCAF weighted loads.

Using the system PCAF method, PG&E has estimated each class' average contribution to the system peak during a single year period.[3] These recorded kW values are converted to forecast system PCAF weighted loads by multiplying them by the ratio given by TY sales divided by recorded sales. The class' TY marginal generation capacity cost revenue equals the class' system PCAF weighted loads for the TY, times the marginal generation capacity cost (including the 15 percent planning reserve requirement adjustment) from Exhibit (PG&E-9), Chapter 2, "Marginal Generation Costs."

2. Marginal Energy Cost Revenue

Marginal energy costs are the costs associated with procuring an additional kWh of energy. The marginal energy costs, presented in Exhibit (PG&E-9), Chapter 2, "Marginal Generation Costs," reflect the costs of the energy (that varies by season and TOU) and an adjustment for the line losses between the generation source and the customers' meters.

To calculate a class' marginal energy cost revenue, PG&E first assigns the forecast sales among five TOU periods[4] using the class' recorded TOU usage pattern. The TY marginal energy cost revenue for a given TOU period equals the marginal energy cost for that period multiplied by the forecast sales in the period. Total marginal energy cost revenue for the class equals the sum of the marginal energy cost revenue across the five TOU periods.

D. Conclusion

PG&E recommends that the Commission adopt its proposed calculations of distribution and generation marginal cost revenues.

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3 Additional information on system PCAFs is provided in the Marginal Cost testimony, Exhibit (PG&E-9), Chapter 9.

4 The proposed five TOU periods, and the hours associated with those periods are: (1) summer peak 5:00 p.m. to 10:00 p.m.; (2) summer partial-peak 3:00 p.m. to 5:00 p.m. and 10:00 p.m. to Midnight; (3) summer off-peak Midnight to 3:00 p.m.; (4) winter partial-peak, 5:00 p.m. to 10:00 p.m.; and (5) winter off-peak, 10:00 p.m. to 5:00 p.m. Summer is defined as June through September and all time periods apply equally seven days a week.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

REVENUE ALLOCATION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
REVENUE ALLOCATION

A. Introduction

In this 2017 General Rate Case (GRC) Phase II, Pacific Gas and Electric (PG&E) is proposing very few changes to revenue allocation. Specifically, the only change PG&E is proposing is for a portion of the Public Purpose Program (PPP) revenue requirement. Although GRC Phase II proposals are usually made to adjust distribution and generation revenue allocations so that classes move towards their share of the marginal cost revenue, as discussed in Chapter 1, "Revenue Allocation and Rate Design Policy," PG&E is proposing in this proceeding to retain the current allocation of distribution and generation revenue requirements in order to minimize the number of changes in this proceeding.

PG&E bases its illustrative revenue allocation on the same general methods proposed in its 2014 GRC Phase II proceeding. In the decision that adopted the settlements filed in that proceeding, Decision (D.) 15-08-005, the Commission adopted two approaches for revenue allocation. The first approach provided methodologies to be used for the *initial* allocation of costs following a decision in that proceeding. Table 3-1 provides a summary of the current and proposed allocation methods for distribution, generation and PPP functional revenues to be used in the initial allocation.

TABLE 3-1
CURRENT AND PROPOSED ALLOCATION METHODS

Line No.	Functional Revenue Category	Customer Group[(a)]	Adopted Approach in Last Phase II (Adopted Methods Were Approved Via Settlement[(b)])	Proposed in This Phase II
1	Distribution	All customers	EPMC, limited through application of caps and floors on Direct Access and Community Choice Aggregation (DA/CCA) customers.	No change to allocation.
2	Public Purpose Programs – Electric Program Investment Charge and Former Public Goods Charge	All customers	Allocation based on current revenue share.	Allocated on percent of total revenue share with generation imputed for DA/CCA customers.
3	Public Purpose Programs – Energy Savings Assistance/Procurement Energy Efficiency Balancing Account	All customers	Allocation based on current revenue share.	Allocated on percent of total revenue share with generation imputed for DA/CCA customers.
4	Public Purpose Programs – California Alternate Rates for Energy (CARE) Surcharge	All customers	All CARE distribution and Conservation Incentive Adjustment (CIA) rate differences will be funded through the CARE surcharge, which will be allocated based on equal cents per kWh. Set once per year.	Same as prior GRC.
5	Generation	Bundled service customers	EPMC, limited through application of caps and floors on bundled customers.	No change to allocation.

(a) "All customers" includes eligible Bundled, Direct Access (DA), Community Choice Aggregation (CCA), and Departing Load (DL) customers.
(b) "Settlement" refers to the Marginal Cost/Revenue Allocation Settlement adopted in D. 15-08-005.

Table 3-2 provides a summary of the current allocation methods for other functional revenues that PG&E is not proposing to adjust in this proceeding.

TABLE 3-2
CURRENT ALLOCATION METHODS FOR OTHER FUNCTIONAL REVENUE

Line No.	Functional Revenue Category	Customer Group[(a)]	Currently Approved Allocation
1	Department of Water Resources Bond Charges	All customers	Equal cents per kWh
2	Competitive Transition Costs (CTC)	All customers	Top 100-hour allocation
3	Nuclear Decommissioning	All customers	Equal cents per kWh
4	Transmission Rates (including the Transmission Revenue Balancing Account Adjustment (TRBAA), Transmission End-Use Customer Refund Adjustment (T-ECRA) and Transmission Access Charge Balancing Account (TACBA) rate)	All customers	12 coincident peak demands (Transmission and T-ECRA) and equal cents per kWh (TACBA and TRBAA)[(b)]
5	Reliability Services	All customers	12 coincident peak demands
6	Energy Cost Recovery Amount	All customers	Equal cents per kWh
7	New System Generation Charge	All customers	12 coincident peak demands
8	Conservation Incentive Adjustment[(c)]	All residential customers	Set residually, reflecting decrements from or increments to schedule rates, to preserve the tiered residential total rate structure pursuant to the constraints set forth D.15-07-001.
9	Power Charge Indifference Adjustment	All eligible DA, CCA and DL customers	Set by vintage proportional to CTC

(a) "All customers" includes eligible Bundled, DA, CCA and Departing Load (DL) customers.
(b) Transmission rates are established by the Federal Energy Regulatory Commission and are not subject to change by the CPUC in this proceeding.
(c) PG&E has not changed its approach to CIA design, but CIA rates are affected by changes to other charges made in this proceeding.

Finally, the second approach adopted by D. 15-08-005 established the revenue allocation methodologies to be applied for revenue requirement changes *between* GRC Phase II proceedings. PG&E's proposal to implement revenue requirement changes between GRC Phase II proceedings is provided in Chapter 1 of this exhibit. In summary, for changes between GRCs, PG&E proposes: (1) to continue to apply the methods set forth in Table 3-1 for PPP charges; and (2) to continue to apply all the methods set forth in Table 3-2 for other functional revenues. Table 3-3 describes the current and proposed approach to changing generation and distribution rates between GRCs. These proposed methods will apply unless specifically addressed in the following rate design chapters.

TABLE 3-3
ALLOCATION METHODS FOR DISTRIBUTION AND GENERATION FUNCTIONAL REVENUES BETWEEN PHASE II PROCEEDINGS

Line No.	Functional Revenue Category	Customer Group[(a)]	Last Adopted Approach in Last Phase II (Adopted Methods Were Approved Via Settlement[(b)]	Proposed in This Phase II
1	Distribution	All customers	Equal percentage changes.[(c)]	Same as prior GRC.
2	Generation	Bundled service customers	Equal percentage changes.	Same as prior GRC.

(a) "All customers" includes eligible Bundled, DA, CCA and DL customers.
(b) "Settlement" refers to the Marginal Cost/Revenue Allocation Settlement adopted in D.15-08-005.
(c) The CPUC fee will continue to be separately allocated on a $/kWh basis per Resolution M-4828.

In this chapter, PG&E describes its proposed approach for determining the initial allocation of costs following a decision in this proceeding. The remainder of this chapter is organized as follows:

- Section B – Model Improvements
- Section C – Distribution Allocation
- Section D – Public Purpose Program Allocation
- Section E – Generation Allocation
- Section F – Conclusion

B. Model Improvements

PG&E's Revenue Allocation and Rate Design (RARD) model already contained many design improvements for the 2014 GRC Phase II. That model was favorably viewed by parties and so its structure has largely been preserved in the 2017 version. Some incremental improvements for the 2017 RARD model include:

- Ability to set caps and floors on individual schedules as well as classes.[1]
- Improved time-of-use definition flexibility for setting generation marginal cost revenue.
- Improved scenario analysis in the setting of Small and Medium Business threshold voltages.

C. Distribution Allocation

PG&E proposes that no changes be made to the allocation of distribution revenue in this proceeding. PG&E will continue to directly assign to each schedule the estimated CARE program discounts and certain non-allocated distribution revenues (i.e., Electric Base Interruptible Program discounts, economic development discounts, employee discounts, other standby revenue, and streetlight facilities charges). PG&E proposes to continue to allocate distribution Family Electric Rate Assistance Program costs to only the residential class.

D. Public Purpose Program Allocation

PPP revenue includes three components: (1) Electric Program Investment Charge and Former Energy Efficiency Public Goods Charge; (2) Procurement Energy Efficiency and Energy Savings Assistance; and (3) the CARE surcharge which funds the cost of the low-income CARE Program.

The first two PPP rate components listed above are currently allocated to customer groups based on an equal percentage change to each component's current revenue. PG&E proposes to allocate these in proportion to each schedule's share of total revenue with generation imputed for DA/CCA customers.

For the third PPP component, the CARE surcharge, PG&E proposes to continue to reset the CARE shortfall rates once each year. These CARE shortfall rates, equal to the difference between the non-CARE and CARE distribution and CIA rates ultimately established in this proceeding, are multiplied

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[1] While PG&E has not proposed a change to distribution and generation revenue allocation here, PG&E's revenue allocation model is fully capable of allocating generation and distribution revenue subject to mitigation through caps and floors or through percent change by component.

by forecast CARE sales to determine the cost of the CARE discount, referred to as the CARE shortfall revenue requirement.

PG&E proposes to continue to reflect the cost of the CARE distribution and CIA discount in the CARE surcharge component of PPP, allocated on an equal cents per kWh basis to all eligible customers, consistent with the language in Pub. Util. Code 327(a)(7) established by enactment of Senate Bill 695 which established Pub. Util. Code Section 739.1 and 739.9.

It is PG&E's position that the first two PPP rate components listed above are not significantly distinguishable and don't require different allocation rules. Table 3-4 below compares the present and proposed allocation methods for these components and illustrates that effect of the simpler proposed method.

TABLE 3-4
ALLOCATION METHODS FOR NON-SURCHARGE PPP COMPONENTS
(MILLIONS OF DOLLARS)

Line No.	Rate Class	Present Allocation (Millions)	Proposed Allocation (Millions)	Difference (Millions)
1	Residential	$196.1	$186.1	$(10.0)
2	Small	63.7	62.3	(1.4)
3	Medium	60.8	64.0	3.2
4	E-19	75.6	77.4	1.8
5	Streetlights	2.6	2.4	(0.2)
6	Standby	3.8	2.6	(1.2)
7	Agriculture	32.0	36.4	4.4
8	E-20	72.3	75.7	3.4
9	System	$506.8	$506.8	$0.0

E. Generation Allocation

PG&E proposes that no changes be made to the allocation of generation revenue in this proceeding.

F. Conclusion

Appendix A, "Revenue and Average Rate Summary at Proposed Rates," shows illustrative revenue results for PG&E's proposed allocation as described in this chapter. PG&E recommends that the Commission adopt its proposed allocation methods for initial allocation of PPP.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

RESIDENTIAL RATE DESIGN

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RESIDENTIAL RATE DESIGN

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E or the Utility) proposals for residential rate design to be implemented pursuant to a decision in Phase II of its 2017 General Rate Case (GRC) Phase II. As described in Chapter 1, "Revenue Allocation and Rate Design Policy" of this exhibit, these proposals include changes to distribution, public purpose program (PPP) and generation rate components. As discussed in Chapter 1, a key objective of PG&E's residential rate proposal is to use marginal cost relationships to set distribution and generation rates,[1] balanced with other objectives such as understandability, equity, and rate stability. PG&E sets forth in this testimony its residential rate design, focusing on changes to total rates.

In summary, PG&E's proposed changes to residential rate design are:

- Schedule E-1:
  - Establish updated rates for Schedules E-1 and EL-1, while continuing to implement the glide path for structural rate changes to residential tiered rates in accordance with the California Public Utilities Commission's (CPUC or Commission) Residential Rate Reform Order Instituting Rulemaking (OIR) decision (D.15-07-001).
- Baseline:
  - Update residential electric baseline quantities, currently at 52.5 percent of total usage, with the most recently available four years of billing data, but change the seasons for electric to a four-month summer and eight-month winter to align the seasons with the new seasons recently approved in D.15-11-013 for Schedule E-TOU;[2]

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[1] PPP rates for the residential customer class are designed in accordance the guidelines described in Chapter 1 of this exhibit.

[2] Public Utilities Code (Pub. Util. Code) Section 739(a)(1) requires that baseline quantities must be set by the Commission between 50 and 60 percent of average usage in a particular territory, except for all-electric customers in the winter season for whom they must be set between 60 and 70 percent of average usage. PG&E's baseline quantities are currently set at 52.5 percent and 62.5 percent of average usage, respectively.

- Expand Territory Q to include additional customers in Santa Cruz County and use the same baseline quantities as those established for Territory X in the summer and Territory P in the winter;
- Provide separate baseline quantities for Territories P and S in the summer;
- Modify the methodology for calculating Territory V baseline quantities;
- Update current residential electric baseline quantities for Schedules E-6 and EL-6, which are based on 6-month summer and winter seasons, with the most recently available four years of billing data; and
- Revise gas baseline quantities at the same percentage of average use as in previous GRC Phase II proceedings.

- Medical Baseline:
  - Eliminate the 4 cent rate credit for non-California Alternate Rates for Energy (CARE) usage exceeding 200 percent of baseline, provide a rate discount in all tiers for non-CARE customers, and change the methodology for calculating usage by tier for all Medical Baseline customers; and
  - Require customers with more than one Medical Baseline allowance to provide additional information that would enable PG&E to more accurately evaluate their need for additional allowances.
- Time-of-Use (TOU) Rates:
  - Establish updated rates for Schedules E-6 and EL-6 based on updated marginal costs;
  - Establish updated rates for Schedules E-TOU and EL-TOU using updated generation marginal costs;
  - Establish a new, optional TOU rate schedule with a maximum non-coincident demand charge, modest fixed monthly customer charge and full, generation and primary distribution marginal cost TOU pricing to, among other things, incent battery storage technologies; and
  - Modify Schedule EV's seasons and TOU periods to reflect updated generation and primary distribution peak hours and costs.
- Master Meter Discounts:
  - Update the electric master meter discounts for Schedules ES, ESL, ET and ETL using recent data with the existing methodology.

These proposed changes, if adopted, would provide more appropriate price signals for incenting more efficient energy usage across a wide range of residential customers.

Table 4-1 summarizes the number of customers and annual usage under each of PG&E's current residential rate schedules.

TABLE 4-1
RESIDENTIAL HOUSEHOLDS AND SALES BY SCHEDULE
JUNE 2015 – MAY 2016

Line No.	Schedule	Description	Current Households[(a)]	Annual GWh Sales[(a)]	Average Annual kWh Sales[(a)]
1	E-1[(b)]	Standard	3,530,000	20,800	5,900
2	EL-1[(c)]	Standard CARE	1,220,000	7,600	6,150
3	E-6[(d),(e)]	TOU	110,000	580	5,600
4	EL-6[(d),(e)]	TOU CARE	10,000	40	7,500
5	ETOU-A[(e)]	TOU, incl. CARE	5,000	*	*
6	ETOU-B[(e)]	TOU, incl. CARE	5,000	*	*
7	EVA	EV Whole House	25,500	390	15,200
8	EVB	EV Separate Meter	500	2	3,400
9	Totals		4,905,000	29,412	6,000

(a) Numbers are rounded.

(b) Includes customers absorbed from Schedules E-7 and E-8, which were eliminated on March 1, 2016.

(c) Includes customers absorbed from Schedules EL-7 and EL-8, which were eliminated on March 1, 2016.

(d) Closed to new participants.

(e) Households are estimated.

* E-TOU-A and E-TOU-B opened for enrollment on March 1, 2016. Without 12 full months of operation, no annual sales data are as yet available for these two new TOU schedules.

The remainder of this chapter is organized as follows:

- Section B – Rate Design for Schedules E-1 and EL-1
- Section C – Baseline Quantities – Gas and Electric
- Section D – Medical Baseline
- Section E – Time-of-Use Rate Design
- Section F – Electric Master Meter Discounts
- Section G – Conclusion

Appendix B, "Present and Proposed Rates" of this exhibit, presents PG&E's proposed illustrative total and unbundled rates for the residential customer class. Appendix G, "Illustrative Bill Impacts of Present Versus Proposed Total Rates" of this exhibit, presents the bill comparison impacts of PG&E's proposed rates.

B. Rate Design for Schedules E-1 and EL-1

1. PG&E's Proposal

In D.15-07-001, the CPUC's 2015 decision in Phase I of the Residential Rate Reform OIR (RROIR) proceeding, the CPUC adopted a multi-year glide path that laid out significant changes to the structure and rates to be charged for usage under PG&E's standard tiered rates, Schedules E-1 and EL-1. These rates currently provide service to approximately 97 percent of PG&E's residential customer base. PG&E proposes to make no further changes to those schedules here. Instead, PG&E will continue to implement the glide path approved in D.15-07-001 in which the number of tiers, the tier differentials and the CARE discount will be gradually reduced through at least 2019 in advance of the planned roll-out of residential default TOU.

PG&E's current Schedule E-1 rate structure is defined as follows:

- Tier 1: usage between zero and 100 percent of baseline;
- Tier 2: usage between 100 and 200 percent of baseline; and
- Tier 3: usage above 200 percent of baseline.

PG&E's Schedule E-1 rate structure in and after 2017 will be defined as follows:

- Tier 1: usage between zero and 100 percent of baseline;
- Tier 2: usage between 100 and 400 percent of baseline; and
- Super User Energy (SUE) Surcharge: usage above 400 percent of baseline.

Even though PG&E is not proposing any structural change to the RROIR-adopted glide path, PG&E's proposed rates reflect the updating of baseline quantities and changing the summer season to four months, June to September, and winter season to eight months, October to May. (This is further discussed in Section C.)

PG&E's proposed update to non-CARE (Schedule E-1) rate levels is shown in Table 4-2 below. PG&E's proposed update to CARE (Schedule EL-1) rate levels is shown in Table 4-3 below. Rates for both schedules have been slightly reduced to reflect the impact of lower baseline quantities, which, in turn, results from lower average usage compared to the previous 4-year period.

TABLE 4-2
CURRENT AND PROPOSED NON-CARE SCHEDULE E-1 RATES BY TIER

Line No.	Tier	October 2016 ($/kWh)	Proposed ($/kWh)	Change ($/kWh)
1	Tier 1	$0.184	$0.181	$(0.003)
2	Tier 2	$0.243	$0.239	$(0.004)
3	Tier 3	$0.403	$0.397	$(0.006)

TABLE 4-3
CURRENT AND PROPOSED CARE SCHEDULE EL-1 RATES BY TIER

Line No.	Tier	October 2016 ($/kWh)	Proposed ($/kWh)	Change ($/kWh)
1	Tier 1	$0.120	$0.118	$(0.002)
2	Tier 2	$0.148	$0.146	$(0.002)
3	Tier 3	$0.218	$0.215	$(0.003)

2. Bill Impacts for E-1 and EL-1

The bill impacts for Schedules E-1 and EL-1 customers are a comparison of bills based on current rates and baseline quantities to proposed rates and baseline quantities with a four-month summer season. These are shown in Appendix G.

C. Baseline Quantities – Gas and Electric

Baseline quantities are the designated daily amounts of electricity and gas that are considered necessary to supply a significant portion of the reasonable energy needs of the average residential customer. While residential and non-residential gas rate design issues are generally litigated in gas Biennial Cost Adjustment Proceedings (BCAP), the proposed gas target baseline quantities applicable during the 2017 GRC cycle are addressed in Phase II of the 2017 GRC, as ordered in D.89-12-057.

PG&E proposes to continue using the currently-adopted methodology, per D.02-04-026, which resolved the CPUC's Baseline Rulemaking, R.01-05-047. This method averages the most recent four calendar years of bill frequency-derived baseline quantities. The current methodology also adjusts for seasonal and vacation home usage, per D.04-02-057, as modified in D.07-09-004.

1. Electric Baseline Quantities

PG&E's electric baseline quantities were last adjusted in D.14-06-013 and implemented on August 1, 2014. In this proceeding, PG&E proposes to use the most recently available four years of seasonal data, which is October 2011 through September 2015, to update baseline quantities. PG&E further proposes to maintain the current electric baseline percentage, per Pub. Util. Code Section 739(a)(1), but change the summer and winter seasons for all of its residential electric rate schedules, except Schedule E-6, to a four-month summer season and eight-month winter seasons. The proposed new season definitions will align the rates of virtually all residential customers both with the recommendation for seasons set forth in Exhibit (PG&E-2), Chapter 12, as well as with the four-month summer and eight-month winter season that the CPUC recently adopted for PG&E's new Schedule E-TOU in PG&E's 2015 Rate Design Window Proceeding (D.15-11-013), based on detailed showings by both PG&E and Office of Ratepayer Advocates (ORA) supporting this change. If adopted here, the summer season for all of PG&E's rates would be June through September and the winter season would be October through May, for all customers except those still on PG&E's legacy TOU Schedule E-6, which, according to D.15-11-013, would retain its seasonal structure until it is phased-out in 2022.

Shortening the summer season would dampen bill volatility in the Central Valley, especially in Kern County. Table 4-4 shows the change in monthly bills for a customer using 150 percent of average usage in Territory W, which includes Kern County. Not only is bill volatility significantly dampened, bills drop by an average of 7 percent during the four most extreme months, June-September. Furthermore, instead of the bill jumping by nearly 140 percent from May-June under the current six-month summer season, it increases by a much more moderate 70 percent under the proposed four-month summer season.

TABLE 4-4
2015 TERRITORY W BILLS AT 150 PERCENT OF AVERAGE KWH
6-MONTH SUMMER VS. 4-MONTH SUMMER

Month	kWh	6-Month	4-Month	Percent Change
January	770	$197	$190	-4%
February	648	$149	$141	-5%
March	605	$131	$127	-4%
April	669	$159	$150	-6%
May	797	$154	$200	30%
June	1,419	$364	$338	-7%
July	1,544	$414	$388	-6%
August	1,570	$424	$398	-6%
September	1,284	$311	$285	-8%
October	886	$181	$236	30%
November	697	$168	$161	-4%
December	799	$208	$201	-4%

PG&E will revise baseline quantities with a revenue neutral rate adjustment for Schedules E-1 and EL-1 (and related master meter schedules) to reflect a four-month summer season as early as January 1, 2019, but no later than the date determined by the Commission for implementation of default TOU for residential customers. Pursuant to the Settlement approved by D.15-11-013, PG&E will retain an updated six-month summer season for Schedules E-6 and EL-6 until these rate schedules are phased out in 2022. PG&E will also retain the six-month summer season for Schedules E-1 and EL-1 until the four-month summer season is approved and implemented, as described above. Finally, the revised baseline quantities utilizing a four-month summer season for Schedule E-TOU and those utilizing a six-month summer season for all other rate schedules will be implemented with a revenue neutral rate change in one step on the first day of the next available season after the effective date of the decision in this proceeding.

PG&E's proposed electric baseline quantities based on a four-month summer season are set forth in Table 4-7 at the end of this section. PG&E's updated baseline quantities for a six-month summer season are set forth in

Table 4-8, also at the end of this section. All revisions to electric baseline quantities should incorporate revenue neutral electric rate adjustments.

PG&E also proposes three technical changes to how it calculates electric baseline quantities to make baseline quantities more equitable, as discussed below.

a. Territory Q

PG&E proposes to expand Territory Q to include the San Lorenzo Valley within Santa Cruz County. Specifically, PG&E proposes that Territory Q be expanded to include customers living within the Santa Cruz County ZIP Codes 95005 (Ben Lomond), 95006 (Boulder Creek), 95007 (Brookdale), 95018 (Felton), 95033 (unincorporated) and 95041 (Mount Hermon). This would affect approximately 10,000 households and would have no material effect on rates for other customers.

Climate data provided by the County of Santa Cruz shows that the San Lorenzo Valley has the same winter climate as that of Territory P, which includes both Lake County and a portion of the Sierra Foothills. In D.14-06-029, the Commission approved changing the winter baseline quantities of Territory Q, which currently includes Santa Cruz County customers living above 1,500 foot elevation, to those of Territory P.

Table 4-5 shows the average maximum and minimum temperatures during the four warmest and four coldest months for selected cities in a specific geographic area. Climate data from the weather station which includes the Ben Lomond and Boulder Creek areas, representing nearly half of the San Lorenzo Valley residents, matches Territory X in the summer and is closest to Territory P in the winter.

TABLE 4-5
UNWEIGHTED MAXIMUM AND MINIMUM TEMPERATURES BY SELECTED AREA[a]

			June – September		November – February	
Line No.	Selected Cities Within a Geographic Area	Climate Zone	Average Maximum	Average Minimum	Average Maximum	Average Minimum
1	San Francisco to Monterey	T	71.9	61.9	53.0	43.3
2	**Ben Lomond & Boulder Creek**	T[b]	**82.3**	**61.9**	**48.4**	**37.0**
3	San Jose to Hollister	X	**82.9**	**61.7**	54.4	40.9
4	Lake County & Sierra Foothills	P	87.2	56.5	**53.4**	**34.1**

(a) 30-year average through 2010.
(b) Below 1500 feet of elevation.

PG&E also proposes to change the summer baseline quantities for Territory Q from those currently assigned to Territory T to Territory X. This would result in significantly higher summer baseline quantities. To summarize, Territory Q customers would be assigned Territory X baseline quantities in the summer and Territory P baseline quantities in the winter.

b. Territories P and S

Neighboring Territories P and S are currently combined for the summer season, but not the winter. PG&E has discovered that moving to a four-month summer season would create significant enough differences in baseline quantities (approximately 2 kilowatt-hours (kWh) per day) to justify separate baseline quantities in each area, as is already the case during the winter season. Therefore, PG&E proposes separate baseline quantities for Territories P and S in the summer.[3]

c. Territory V

In D.14-06-029, the Commission approved a formula proposed by PG&E to lower baseline quantities in Territory V that had become highly inflated due to significant non-residential usage by many residential customers. While this change in methodology, which involved removing the highest 2.94 percent of basic electric bills and 5.30 percent of

[3] Territory P includes Lake County plus the Sierra foothills, from Butte County in the north to Tuolumne County in the south. Territory S covers the portion of the Central Valley, from Glenn and Butte counties in the north to Stanislaus and Tuolumne counties in the south.

all-electric bills from the calculations based on a comparison of high usage Territory V customers to those in Territory T, was successful in significantly lowering baseline quantities for basic electric customers, all-electric baseline quantities remain stubbornly high in Territory V.

Given that Territories T and V are both coastal climate zones, with Territory V having a cooler climate than T, PG&E proposes instead to base the Territory V baseline quantities on their average ratio to Territory T baseline quantities for the years 1993 through 2008 when the ratio was relatively stable, as shown in Table 4-6.[4] Compared to the current methodology, this change would leave baseline quantities relatively unchanged for the 45,000 basic electric households in Territory V, while producing a 13 percent increase in baseline quantities for the more than 1,000 all-electric apartment dwellers billed under Schedule EM.[5] However, it would lower baseline quantities by 22 percent for the 7,500 individually metered all-electric customers.

TABLE 4-6
RATIO OF TERRITORY V TO TERRITORY T BASELINE QUANTITIES
FOR INDIVIDUALLY METERED CUSTOMERS

	Month and Year Adopted by Commission				2017 GRC[(a)]	
End-Use	July 1993	May 2002	May 2006	May 2008	Current	Proposed
All-Electric						
Summer	1.47	1.47	1.38	1.49	1.63	1.48
Winter	1.22	1.28	1.31	1.36	1.82	1.30
Basic Electric						
Summer	1.12	1.02	1.07	1.16	1.11	1.12
Winter	1.09	1.02	1.07	1.13	1.18	1.10

(a) Six-month summer season. Ratios for the four-month summer season are slightly different.

4 The customer bills used to determine these baseline quantities are from the years 1989-1991 and 1998-2006. Baseline quantities did not change from 1994-2001. PG&E averaged the three highest ratios for individually metered customers and the two highest ratios for master metered customers.

5 Schedule EM, which applies to master-metered customers, has separate baseline quantities.

2. Gas Baseline Quantities

PG&E's proposal for gas baseline quantities uses the most recently available four years of seasonal data, which is November 2011 through October 2015 for gas. PG&E's gas baseline quantities, which were not contested, were last adjusted in D.15-08-005 (2014 GRC Phase II). PG&E proposes to continue to set its gas baseline quantities at 60 percent of average usage in the summer and 70 percent in the winter. Like electric changes, PG&E proposes to implement the proposed gas baseline quantities with a revenue neutral rate adjustment in one step on the first day of the next available season after the effective date of the decision in this proceeding—either April 1 or November 1. However, PG&E is not proposing to change summer and winter seasons for gas. The updated gas baseline quantities are shown in the bottom panel of Table 4-7.

TABLE 4-7
RESIDENTIAL TARGET BASELINE QUANTITIES BASED ON FOUR-MONTH SUMMER SEASON FOR ELECTRIC AND SIX-MONTH SUMMER SEASON FOR GAS(1)

	SUMMER (2)			WINTER (2)			SUMMER (2)			WINTER (2)		
TERRITORY	Current Daily	**2017 Target Daily**	Pctg. Chg.	Current Daily	**2017 Target Daily**	Pctg. Chg.	Current Daily	**2017 Target Daily**	Pctg. Chg.	Current Daily (3)	**2017 Target Daily**	Pctg. Chg.
	E-1, E-6, ES, ESR, ET, ETOU-A (3) (and CARE)						**EM (4)** (and CARE)					
	ALL-ELECTRIC QUANTITIES (kWh)						ALL-ELECTRIC QUANTITIES (kWh)					
P	16.4	**15.5**	-5.5%	29.6	**26.0**	-12.2%	9.1	**8.4**	-7.7%	15.4	**13.9**	-9.7%
Q	8.3	**8.6**	3.6%	29.6	**26.0**	-12.2%	5.4	**7.0**	29.6%	15.4	**13.9**	-9.7%
R	18.8	**20.3**	8.0%	29.8	**26.7**	-10.4%	9.2	**9.3**	1.1%	15.4	**12.9**	-16.2%
S	16.4	**18.1**	10.4%	27.1	**23.6**	-12.9%	9.1	**9.6**	5.5%	15.3	**12.4**	-19.0%
T	8.3	**7.2**	-13.3%	14.9	**12.5**	-16.1%	5.4	**4.9**	-9.3%	9.8	**8.5**	-13.3%
V	13.6	**10.4**	-23.5%	26.6	**15.8**	-40.6%	8.0	**6.1**	-23.8%	14.5	**10.5**	-27.6%
W	20.8	**23.0**	10.6%	20.6	**18.8**	-8.7%	10.3	**11.4**	10.7%	12.9	**11.2**	-13.2%
X	9.3	**8.6**	-7.5%	16.7	**14.1**	-15.6%	7.5	**7.0**	-6.7%	14.0	**12.1**	-13.6%
Y	13.0	**12.1**	-6.9%	27.1	**23.9**	-11.8%	8.1	**6.9**	-14.8%	18.0	**13.4**	-25.6%
Z	7.7	**6.7**	-13.0%	18.7	**15.6**	-16.6%	4.8	**3.8**	-20.8%	12.5	**8.7**	-30.4%
	BASIC QUANTITIES (kWh)						BASIC QUANTITIES (kWh)					
P	13.8	**13.8**	0.0%	12.3	**11.4**	-7.3%	5.9	**4.7**	-20.3%	5.6	**4.9**	-12.5%
Q	7.0	**10.1**	44.3%	12.3	**11.4**	-7.3%	3.9	**5.3**	35.9%	5.6	**4.9**	-12.5%
R	15.6	**18.1**	16.0%	11.0	**10.7**	-2.7%	6.6	**7.7**	16.7%	5.3	**5.0**	-5.7%
S	13.8	**15.4**	11.6%	11.2	**10.6**	-5.4%	5.9	**6.5**	10.2%	5.1	**5.0**	-2.0%
T	7.0	**6.6**	-5.7%	8.5	**7.6**	-10.6%	3.9	**3.6**	-7.7%	4.8	**4.2**	-12.5%
V	8.7	**7.3**	-16.1%	10.6	**8.4**	-20.8%	4.3	**4.0**	-7.0%	5.2	**4.7**	-9.6%
W	16.8	**19.7**	17.3%	10.1	**10.2**	1.0%	7.4	**7.9**	6.8%	5.5	**5.0**	-9.1%
X	10.1	**10.1**	0.0%	10.9	**9.8**	-10.1%	5.4	**5.3**	-1.9%	6.2	**5.6**	-9.7%
Y	10.6	**10.6**	0.0%	12.6	**11.4**	-9.5%	9.0	**7.5**	-16.7%	8.3	**7.8**	-6.0%
Z	6.2	**6.0**	-3.2%	9.0	**7.7**	-14.4%	5.3	**4.2**	-20.8%	5.9	**5.3**	-10.2%
	G-1, GS, GT (and CARE)						**GM** (and CARE)					
	GAS QUANTITIES (therms)						GAS QUANTITIES (therms)					
P	0.46	**0.39**	-15.2%	2.18	**1.92**	-11.9%	0.33	**0.29**	-12.1%	1.06	**0.86**	-18.9%
Q	0.65	**0.59**	-9.2%	2.02	**1.85**	-8.4%	0.59	**0.52**	-11.9%	0.79	**0.69**	-12.7%
R	0.43	**0.36**	-16.3%	1.82	**1.65**	-9.3%	0.36	**0.33**	-8.3%	1.26	**0.99**	-21.4%
S	0.46	**0.39**	-15.2%	1.92	**1.75**	-8.9%	0.33	**0.29**	-12.1%	0.66	**0.60**	-9.1%
T	0.65	**0.59**	-9.2%	1.79	**1.59**	-11.2%	0.59	**0.52**	-11.9%	1.12	**0.99**	-11.6%
V	0.69	**0.59**	-14.5%	1.79	**1.69**	-5.6%	0.56	**0.49**	-12.5%	1.22	**1.16**	-4.9%
W	0.46	**0.39**	-15.2%	1.69	**1.52**	-10.1%	0.29	**0.26**	-10.3%	0.89	**0.76**	-14.6%
X	0.59	**0.49**	-16.9%	2.02	**1.85**	-8.4%	0.36	**0.33**	-8.3%	0.79	**0.69**	-12.7%
Y	0.82	**0.69**	-15.9%	2.64	**2.35**	-11.0%	0.49	**0.39**	-20.4%	1.06	**0.86**	-18.9%

(1) Usage is from October 2011 through September 2015.
(2) The Summer season is June through September for Electric and April through October for Gas.
The Winter season is October through May for Electric and November through March for Gas.
(3) These baseline allowances cover 98 percent of electric households in PG&E's service territory.
(4) These baseline allowances cover 2 percent of electric households in PG&E's service territory.

TABLE 4-8
RESIDENTIAL TARGET BASELINE QUANTITIES BASED ON SIX-MONTH SUMMER SEASON(1)

	SUMMER (2)			WINTER (2)			SUMMER (2)			WINTER (2)		
TERRITORY	Current Daily	**2017 Target Daily**	Pctg. Chg.	Current Daily	**2017 Target Daily**	Pctg. Chg.	Current Daily	**2017 Target Daily**	Pctg. Chg.	Current Daily (3)	**2017 Target Daily**	Pctg. Chg.
	E-1, E-6, ES, ESR, ET, ETOU-A (3) (and CARE)						**EM (4)** (and CARE)					
	ALL-ELECTRIC QUANTITIES (kWh)						ALL-ELECTRIC QUANTITIES (kWh)					
P	16.4	**14.7**	-10.4%	29.6	**27.7**	-6.4%	9.1	**8.0**	-12.1%	15.4	**14.9**	-3.2%
Q	8.3	**8.4**	1.2%	29.6	**27.7**	-6.4%	5.4	**7.1**	31.5%	15.4	**14.9**	-3.2%
R	18.8	**18.6**	-1.1%	29.8	**27.8**	-6.7%	9.2	**8.5**	-7.6%	15.4	**13.6**	-11.7%
S	16.4	**16.7**	1.8%	27.1	**24.8**	-8.5%	9.1	**8.9**	-2.2%	15.3	**13.0**	-15.0%
T	8.3	**7.3**	-12.0%	14.9	**13.2**	-11.4%	5.4	**5.0**	-7.4%	9.8	**9.0**	-8.2%
V	13.6	**10.8**	-20.6%	26.6	**17.1**	-35.7%	8.0	**6.6**	-17.5%	14.5	**11.5**	-20.7%
W	20.8	**20.4**	-1.9%	20.6	**18.7**	-9.2%	10.3	**10.3**	0.0%	12.9	**11.7**	-9.3%
X	9.3	**8.4**	-9.7%	16.7	**14.9**	-10.8%	7.5	**7.1**	-5.3%	14.0	**12.9**	-7.9%
Y	13.0	**12.2**	-6.2%	27.1	**25.2**	-7.0%	8.1	**6.8**	-16.0%	18.0	**14.0**	-22.2%
Z	7.7	**6.8**	-11.7%	18.7	**16.9**	-9.6%	4.8	**3.8**	-20.8%	12.5	**9.4**	-24.8%
	BASIC QUANTITIES (kWh)						BASIC QUANTITIES (kWh)					
P	13.8	**12.6**	-8.7%	12.3	**11.9**	-3.3%	5.9	**4.5**	-23.7%	5.6	**5.2**	-7.1%
Q	7.0	**9.7**	38.6%	12.3	**11.9**	-3.3%	3.9	**5.2**	33.3%	5.6	**5.2**	-7.1%
R	15.6	**16.0**	2.6%	11.0	**10.5**	-4.5%	6.6	**6.9**	4.5%	5.3	**5.0**	-5.7%
S	13.8	**13.9**	0.7%	11.2	**10.5**	-6.2%	5.9	**6.1**	3.4%	5.1	**5.0**	-2.0%
T	7.0	**6.6**	-5.7%	8.5	**7.9**	-7.1%	3.9	**3.7**	-5.1%	4.8	**4.4**	-8.3%
V	8.7	**7.4**	-14.9%	10.6	**8.7**	-17.9%	4.3	**4.0**	-7.0%	5.2	**4.9**	-5.8%
W	16.8	**17.3**	3.0%	10.1	**9.6**	-5.0%	7.4	**7.1**	-4.1%	5.5	**5.0**	-9.1%
X	10.1	**9.7**	-4.0%	10.9	**10.1**	-7.3%	5.4	**5.2**	-3.7%	6.2	**5.8**	-6.5%
Y	10.6	**10.3**	-2.8%	12.6	**11.9**	-5.6%	9.0	**6.4**	-28.9%	8.3	**8.0**	-3.6%
Z	6.2	**5.9**	-4.8%	9.0	**8.4**	-6.7%	5.3	**3.6**	-32.1%	5.9	**5.6**	-5.1%

(1) Data is from November 2011 through October 2015.
(2) The Summer season is May through October. The Winter season is November through April.
(3) These baseline allowances cover 98 percent of electric households in PG&E's service territory.
(4) These baseline allowances cover 2 percent of electric households in PG&E's service territory.

D. Medical Baseline

PG&E proposes the following reforms to the Medical Baseline Program which will result in both modest increases in total benefits as well as a more equitable sharing of benefits among all non-CARE Medical Baseline customers.

1. End the four-cent per kWh credit for non-CARE Medical Baseline customers for usage exceeding 200 percent of baseline beginning in 2017. Neither Southern California Edison Company (SCE) nor San Diego Gas & Electric Company offers such a credit.

2. Change the methodology for calculating Tier 2 and Tier 3 usage for Medical Baseline customers to the same methodology used for non-Medical Baseline customers. This would align PG&E's methodology with SCE's current practice.
3. For non-CARE Medical Baseline, apply an equal cents discount to all usage by reducing the Conservation Incentive Adjustment (CIA) by an amount equal to the Department of Water Resources (DWR) bond charge, currently approximately 0.5 cents per kWh.

1. Background

When Medical Baseline was first implemented in 1984, it was designed to prevent customers from paying the higher over-baseline rate for medically necessitated usage that exceeded baseline. The intent was to avoid penalizing customers who had the same non-medical household usage as their neighbors, but whose medical usage pushed their total usage into the higher-priced tier.[6] In addition, Medical Baseline was designed to treat all customers the same, regardless of size, by providing them the exact, same Medical Baseline allowance: 500 kWh per month, with an option for additional Medical Baseline allowances, if warranted. Consequently, if the tier differential were 3 cents per kWh, the maximum benefit any customer would receive was $15 per month for a single Medical Baseline allowance.

When tiers for usage exceeding 130 percent of baseline were first adopted in 2001, after the Energy Crisis began, PG&E based the calculation of upper-tier usage for Medical Baseline customers on multiples of Tier 1 defined as: Standard Baseline Allowance + Medical Baseline Allowance. Consequently, the range of usage for all higher tiers for Medical Baseline customers was now based on this new, significantly higher Tier 1 definition. And because a single Medical Baseline allowance of 500 kWh per month is greater than most customers' standard baseline allowance, it now takes more than twice the usage than previously for an average Medical Baseline customer to exceed 200 percent of baseline. In 2017, when the Tier 2 definition changes, it will still take more than twice the usage for a Medical Baseline customer to exceed 400 percent of baseline compared to a

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[6] There were just two tiers when Medical Baseline quantities were established.

non-Medical Baseline customer. In contrast, SCE bases the usage in excess of Tier 1 on just the standard baseline allowance. Table 4-9, below, provides a comparison of the methodologies used to calculate the usage range of each tier. As can be seen, there is a huge difference in usage between the threshold at which a PG&E Medical Baseline customer will reach Tier 3 in 2017 compared to that based on the methodology currently employed by SCE, and proposed in this proceeding by PG&E.

TABLE 4-9
TIERED USAGE CALCULATIONS: STANDARD BASELINE VS. MEDICAL BASELINE

Average Standard Baseline Allowance = 350 kWh

Tier	Percent of Baseline	Standard Baseline Calculation (kWh)	Current Medical Baseline Calculation (kWh)	Proposed Medical Baseline Calculation (kWh)
Tier 1	0% to 100%	0 to 350	0 to 850	0 to 850
Tier 2	100% to 400%	350 to 1,400	850 to 3,400	850 to 1,900
Tier 3 (SUE)	Over 400%	Over 1,400	Over 3,400	Over 1,900

Consequently, very large customers have greater amounts of usage assessed at lower tier rates than lower usage customers. This means that larger customers can receive greater Medical Baseline benefits than smaller customers despite having the same number of Medical Baseline allowances, as further shown below in Table 4-10. Under the current methodology, the medium customer in the example shown below will save about $38 per month in 2017, while a customer with three times as much usage will save more than four times as much. This amount increases with each additional Medical Baseline allowance. Therefore, the current tier calculation methodology used by PG&E fails to provide the same dollar benefit to customers with the same number of Medical Baseline Allowances.

TABLE 4-10
IMPACT OF MEDICAL BASELINE ON VERY LARGE VS. MEDIUM NON-CARE CUSTOMERS

Very Large User	No Medical		With Medical		Savings
	kWh	Charge	kWh	Charge	
Tier 1:	350	$70	850	$169	
Tier 2:	1,400	384	1,850	508	
Tier 3 (SUE):	950	382	0	0	
Total	2,700	$836	2,700	$677	$159
Medium User	No Medical		With Medical		Savings
	kWh	Charge	kWh	Charge	
Tier 1:	350	$70	850	$169	
Tier 2:	550	151	50	14	
Tier 3 (SUE):	0	0	0	0	
Total	900	$221	900	$183	$38

2. Changing Tiered Usage Methodology

PG&E proposes that the same range of usage applicable to Tiers 2 and 3 for non-Medical Baseline customers be used for Medical Baseline customers. Tier 1 would continue to include the additional Medical Baseline allowance(s). This would align PG&E's tier calculation methodology with that used by SCE. The primary impact would be to significantly lower the savings for very large customers relative to smaller customers. In the example shown below in Table 4-11, a very large customer would now save $101 per month instead of $159 per month, less than three times what the medium customer would save, down from more than four times.

TABLE 4-11
IMPACT OF TIER CALCULATION PROPOSAL
ON VERY LARGE MEDICAL BASELINE CUSTOMER

Very Large User	New Method		Savings
	kWh	Bill	
Tier 1:	850	$169	
Tier 2:	1,400	384	
Tier 3 (SUE):	450	181	
Total	2,700	$734	$101

Because of the expansion of Tier 2 to include usage up to 400 percent of baseline in 2017, the proposed change in the Medical Baseline tier calculation methodology would affect only a small percentage of Medical Baseline customers. Less than 7 percent of Medical Baseline customers have any usage exceeding 400 percent of baseline. In fact, the top 1 percent account for over 70 percent of this usage. PG&E estimates that this proposed change to the Medical Baseline tiering methodology would increase revenue by nearly $700,000 per year for non-CARE Medical Baseline customers and by over $200,000 per year for CARE Medical Baseline customers. These changes are appropriate to avoid giving high usage Medical Baseline customers a greater benefit than that received by lower usage Medical Baseline customers.

3. Four Cent Rate Credit

PG&E proposes to end the 4 cent credit on usage exceeding 200 percent of baseline for non-CARE Medical Baseline customers for the following reasons. First, this rate credit, which currently costs $1.3 million per year, would increase to about $2.9 million in 2017 as a result of PG&E's proposal to reduce the thresholds at which Medical Baseline customers exceed 200 percent of baseline. This proposed change would more than double the Medical Baseline usage that currently exceeds 200 percent of baseline. Per the example shown in Table 4-9, Medical Baseline customers would exceed 200% of baseline upon reaching 1,201 kWh per month, under PG&E's proposal, compared to the 1,701 kWh currently in effect. Hence, significantly more usage would be eligible for the 4 cent credit under PG&E's proposal. Second, just 1 percent of all Medical Baseline customers currently receive over half of the credits, more than $700,000 per year. In 2017, the amount received by this top 1 percent would increase to $1 million, albeit at a smaller percentage of the total. Consequently, the 4-cent rate credit does little but reward high energy usage, and should be eliminated.

4. Reduction in Conservation Incentive Adjustment Charge

PG&E proposes to reduce the non-CARE CIA rate component by an amount equal to the DWR bond charge, approximately 0.5 cents per kWh, to provide a rate credit in all tiers for non-CARE Medical Baseline customers.

Not only would this increase benefits by over $4 million per year, the benefits would be spread more equitably by being applicable to all usage, including Tier 1 usage.

5. Summary of Changes in Non-CARE Medical Baseline Benefits

The combined impact of the changes proposed by PG&E would not only increase total benefits, but would result in a more equitable distribution of benefits among non-CARE Medical Baseline customers by shifting benefits from very large users to smaller users. Average discounts from the DWR Bond charge reduction, in addition to the ongoing savings from Medical Baseline allowances, would be about $4.50 per month for non-CARE customers. The result of this change, along with changes to tiering and the elimination of the 4 cent credit are shown in Table 4-12. Overall, these changes would still increase total non-CARE Medical Baseline Program benefits by $700,000 per year.

TABLE 4-12
CURRENT AND PROPOSED NON-CARE MEDICAL BASELINE PROGRAM BENEFITS

Line No.	Benefit	Savings (Million)
1	Medical Baseline Allowance	$31.3
2	Modify Medical Baseline Tiering	(0.7)
3	Eliminate 4-Cent Credit	(2.9)
4	Subtract DWR Bond Charge From CIA	4.3
5	Total Proposed Benefits	$32.0

6. Impact of Medical Baseline Tiering on CARE Income Verification

In D.12-08-044, the CPUC authorized PG&E to begin removing CARE customers unable to reduce their consumption below 600 percent of baseline in single month, as well as requiring those using between 400 percent and 600 percent to submit IRS income tax verification and to agree to an Energy Savings Assistance Program visit to help them reduce consumption. Since PG&E implemented this decision in July 2013, the number of non-Medical Baseline CARE customers exceeding 20,000 kWh per year (the equivalent *average annual* baseline of 470 percent), has dropped 80 percent, from about 16,500 to 3,200. For CARE Medical

Baseline customers, however, the number has dropped just 15 percent, from 3,400 to 2,900.

As a consequence of the current tiering methodology, most Medical Baseline customers using more than 20,000 kWh per year have never been subject to post enrollment income verification or the need to reduce their non-medical consumption below 600 percent of baseline to remain in the program. This effect is even more pronounced among Medical Baseline customers using more than 50,000 kWh per year. A single Medical Baseline allowance allows half of these customers to keep their usage below 600 percent of baseline. Additional Medical Baseline allowances enable the other half to do the same.

As an extreme example, a Medical Baseline customer using 120,000 kWh per year would ordinarily be ineligible for CARE. However, having five Medical Baseline allowances, equal to 2,500 kWh per month or 30,000 kWh per year, would enable it to keep its usage below the 600 percent threshold and qualify for CARE. In contrast, a non-Medical Baseline customer with 90,000 kWh of annual non-medical usage would not be eligible for CARE.

PG&E estimates that aligning its tiering methodology for Medical Baseline with that of SCE would subject approximately 1,000 of its largest CARE Medical Baseline customers to CARE income verification.

7. Multiple Medical Baseline Allowances

Another issue PG&E would like to address is multiple Medical Baseline allowances. Although 98.6 percent of Medical Baseline customers have just one allowance, the current Medical Baseline application form does not request all of the necessary data to adequately evaluate a customer’s request for additional allowances. In addition, red flags are raised by fact that Medical Baseline customers with two allowances use twice as much electricity as those with one allowance, while Medical Baseline customers with three or more allowances use three times as much, as shown in Table 4-13.

TABLE 4-13
MEDICAL BASELINE CUSTOMERS AND USAGE PER NUMBER OF ALLOWANCES

Medical Baseline Allowances	Number of Customers	Percent of Total	Annual Average kWh
1	159,908	98.6%	9,251
2	1,755	1.1	17,315
3 or More	449	0.3	28,962
Total	162,112	100.0%	9,393

Therefore, PG&E requests that Medical Baseline customers with more than one allowance be required to submit an updated application that includes, in addition to the data which they must already provide and as a condition for continuing to receiving the additional allowance(s), the following data.

a. Number of hours per day each medical device is operated;
b. Maximum temperature setting if the customer has cooling needs;
c. Minimum temperature setting if the customer has heating needs; and
d. The approximate square footage of the dwelling if b or c is required.[7]

This data will allow PG&E to reasonably estimate a customer's need for additional gas and/or electricity for medical needs. In the meantime, PG&E will change its current application form to request this additional data from new applicants or those who are reapplying.

E. Time-of-Use Rate Design

1. PG&E's Rate Design Proposals

PG&E is proposing updates and/or changes to four existing residential TOU rates as well as proposing a new, optional TOU rate. Schedules E-6 and E-TOU (Options A and B) were part of PG&E's Settlement with the Solar Energy Industries Association and ORA, adopted by the CPUC in D.15-11-013. No structural changes are being proposed for these schedules, although the marginal costs underlying their respective TOU periods are being updated. In contrast, PG&E is proposing new seasons and TOU periods for Schedule EV as well as updating the underlying

[7] Customers would check one of the following: Less than 1,000 square feet, 1,000 to 1,499 sq. ft., 1,500 to 1,999 sq. ft., 2,000 to 2,500 sq. ft. or greater than 2,500 sq. ft.

marginal costs. PG&E is also proposing an optional TOU tariff with a maximum demand charge, Schedule E-DMD.

PG&E proposes that all TOU rate changes between GRCs be done on an equal cents basis to maintain the marginal cost differences between each TOU period. Otherwise, an equal percentage increase in TOU rates will cause the marginal cost price differentials to drift apart as peak rates increase faster than off-peak rates on a per kWh basis.

For comparison purposes, the marginal cost differentials between the summer peak and winter-off peak periods, typically the largest price differential for TOU rate schedules, are shown below in Table 4-14 for each of PG&E's residential TOU rates.

TABLE 4-14
2017 TOU MARGINAL COST DIFFERENTIALS
SUMMER PEAK VS. WINTER OFF-PEAK

Line No.	Schedule	Summer Peak Period	Includes Primary Distribution	Marginal Cost Differential Per kWh
1	E-TOU-A	3 p.m. - 8 p.m., Mon-Fri	No	$0.070
2	E-TOU-B	4 p.m. - 9 p.m., Mon-Fri	No	$0.082
3	E-6	1 p.m. - 7 p.m., Mon-Fri	Yes	$0.078
4	E-DMD	5 p.m. - 10 p.m., All Days	Yes	$0.129
5	EV	4 p.m. - 10 p.m., All Days	Yes	$0.132

2. E-6 Rate Design

Schedule E-6 maintains its pre-existing TOU periods and seasons, as agreed in PG&E's Settlement. This creates a number of rate design anomalies because (1) the old summer season requires the summer peak price signal to be sent during May and October, which are no longer part of the summer peak period; (2) the summer peak period of 1 p.m. to 7 p.m. includes hours that should either be in the summer part-peak or off-peak periods; and (3) the portion of the summer part-peak period that includes weekdays mixes the high cost evening hours of 7 p.m. to 9 p.m. with the low cost hours of 10 a.m. to 1 p.m. on weekdays. One consequence of this is that the summer part-peak price is nearly the same as the summer peak price. Another is that the rate charged on weekdays from 10 a.m. to 1 p.m.

will be too high, relative to marginal costs, while the rate from between 7 p.m. to 9 p.m. on weekdays will be too low.

PG&E has updated the marginal costs for Schedule E-6 based on its applicable seasons and TOU periods. Current and proposed E-6 rates (Tier 1 only) are shown in Table 4-15.

TABLE 4-15
CURRENT AND PROPOSED E-6 RATES (TIER 1 ONLY)

Line No.	TOU Period	October 2016 ($/kWh)	PG&E Proposed ($/kWh)	Change ($/kWh)
1	Summer Peak	$0.34	$0.24	$(0.10)
2	Summer Part-Peak	0.23	0.23	0.00
3	Summer Off-Peak	0.15	0.17	0.02
4	Winter Peak	0.17	0.18	0.01
5	Winter Off-Peak	0.16	0.16	0.00

3. E-TOU Rate Design

PG&E's rate design for Schedules ETOU-A (baseline credit) and ETOU-B (no baseline credit) were approved in D.15-11-013. Both schedules have summer peak periods that include weekday evenings, but not weekend evenings. At the time these schedules were proposed, only generation marginal costs were examined. However, an examination of primary distribution marginal costs for this proceeding has revealed that they vary over a much broader time period, including summer weekends. Consequently, because Schedule E-TOU both excludes weekends from its summer peak period and lacks a summer part-peak period, primary distribution marginal costs cannot be included in the E-TOU summer peak price differential.[8] This significantly narrows the price differential between the summer peak and off-peak periods.

PG&E has updated marginal costs and will adjust the baseline credit for E-TOU-A to reflect the weighted average of over-baseline rates to baseline rates. The baseline credit will be adjusted every time rates are changed.

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8 Additional guidance is provided in Chapter 1, Revenue Allocation and Rate Design Policy, p. 1-8, of this exhibit.

4. New Optional Demand Charge E-DMD Rate Design

Because three quarters of solar output occurs between 10 a.m. and 4 p.m., PG&E is proposing an optional demand charge schedule with a year-round peak period to incent the installation of battery storage technology to allow solar electricity to be stored when it is plentiful and used when it is not, later in the evening. This rate schedule could also be used by customers without solar or a storage battery to reduce or shift their maximum demand and usage during the summer peak period to reduce their costs, as well as utility costs.

Schedule E-DMD would have a demand charge of $8.40 per kilowatt (kW) of maximum (non-coincident) demand[9] and a fixed monthly service (customer) charge of $4 per month ($1 per month for CARE customers). This new optional rate would be PG&E's most accurate rate design for residential customers and would look similar to PG&E's proposed optional Schedule A-1 DMD for the Small Light & Power class. (See Chapter 5, Section E.) In addition, Schedule E-DMD would differ from residential E-TOU by having a summer peak, summer part-peak and winter peak period seven days a week. This rate would also be untiered. The proposed TOU periods for Schedule E-DMD are shown in Table 4-16.

TABLE 4-16
PROPOSED E-DMD TOU PERIODS

Summer (June-September)		
Peak:	5:00 p.m. to 10:00 p.m.	All Days
Partial-Peak:	3:00 p.m. to 5:00 p.m.	All Days
	10:00 p.m. to 12:00 a.m.	All Days
Off-Peak:	12:00 a.m. to 3:00 p.m.	All Days
Winter (October-May)		
Peak	5:00 p.m. to 10:00 p.m.	All Days
Off-Peak:	10:00 p.m. to 5:00 p.m.	All Days

9 The demand charge is set at zero and the customer charge is set at $1.00 for the CARE version of E-DMD to prevent distribution energy rates from going negative.

The E-DMD price differentials between TOU periods would reflect the marginal cost price differences for both generation and coincident (primary) distribution. Energy rates would be about 6.5 cents per kWh lower across-the-board to reflect the $8.40 per kW maximum demand charge. This rate structure would also be similar to mandatory TOU Schedules E-19 and E-20, which serve PG&E's largest customers, except that the peak and part-peak coincident generation and distribution capacity costs currently recovered through demand charges for Schedules E-19 and E-20 would instead be recovered through peak and part-peak energy charges. The proposed rates for non-CARE Schedule E-DMD are shown in Table 4-17 below.

TABLE 4-17
PROPOSED NON-CARE E-DMD RATES

Line No.	Charges	PG&E Proposed ($/kWh)
1	Summer Peak	$0.27
2	Summer Part-Peak	$0.20
3	Summer Off-Peak	$0.15
4	Winter Peak	$0.16
5	Winter Off-Peak	$0.14
6	Monthly Demand (per kW)	$8.40
7	Monthly Service Fee (per unit)	$4.00

5. Electric Vehicle (EV) Rate Design

PG&E proposes to change the seasons and TOU periods for Schedule EV to reflect newly updated marginal costs. Providing more accurate TOU periods will provide EV customers with greater incentives to charge their vehicles at the least expensive times of the day for both the generation and distribution systems. PG&E has proposed different TOU periods than those proposed for E-DMD to reflect the different needs and reality of EV customers. These are shown below in Table 4-18.

TABLE 4-18
PROPOSED EV TOU PERIODS

Summer (June-September)		
Peak:	4:00 p.m. to 10:00 p.m.	All Days
Partial-Peak:	Noon to 4:00 p.m.	All Days
	10:00 p.m. to 1:00 a.m.	All Days
Off-Peak:	1:00 a.m. to Noon	All Days
Winter (October-May)		
Peak	4:00 p.m. to 10:00 p.m.	All Days
Partial-Peak:	10:00 p.m. to 1:00 a.m.	All Days
Off-Peak:	1:00 a.m. to 4:00 p.m.	All Days

Unlike standard TOU rates where the primary goal is for customers to shift and/or reduce existing peak usage, EV customers are adding significant new load. As a result, *when* they charge their vehicles can be far more important than shifting or reducing their current consumption because of the immediate impact recharging can have on utility costs. For this reason, choosing the hours in the off-peak period is just as important as choosing the hours in the summer peak period.

The other issue is price. EVs are competing with hybrids and other highly mileage-efficient cars. Given the rough parity between electric prices and gasoline prices in which 20 cents per kWh is equal to about $2.00 per gallon, PG&E has chosen to limit the off-peak price to 15 cents per kWh. Although this is significantly higher than the current average off-peak rate of 11.8 cents per kWh, it is still less expensive than the current equivalent price of gas. However, this necessitates inflating peak and part-peak prices by about 3.3 cents per kWh to make up the difference.

Consequently, PG&E has chosen to expand the hours of the summer and winter part-peak periods, compared with those designed for E-DMD, to increase the number of kWh over which to spread the revenue lost from keeping off-peak rates at 15 cents per kWh. The upside of this is that encouraging customers to recharge their vehicles during the off-peak period makes it less likely that they will recharge their vehicles during the summer peak period, which could raise rates for other customers by necessitating capacity additions to handle the increased loads. Current and proposed Schedule EV rates are shown in Table 4-19.

TABLE 4-19
CURRENT AND PROPOSED EV RATES

Line No.	TOU Period	October 2016 ($/kWh)	PG&E Proposed ($/kWh)	Change ($/kWh)
1	Summer Peak	$0.45	$0.37	$(0.08)
2	Summer Part-Peak	$0.24	$0.28	$0.04
3	Summer Off-Peak	$0.12	$0.15	$0.03
4	Winter Peak	$0.31	$0.26	$(0.05)
5	Winter Part-Peak	$0.19	$0.25	$0.06
6	Winter Off-Peak	$0.12	$0.15	$0.03

Finally, there currently is a cap of 60,000 customers taking service on Schedule EV. Given the call for more EVs by the Governor, legislature and various environmental groups to combat climate change, PG&E requests that this cap be removed.[10]

6. Bill Impacts for TOU Rate Schedules

The bill impacts are a comparison of bills based on current rates and baseline quantities to proposed rates and baseline quantities with a four-month summer season, with the exception of Schedule E-6, which maintains the six-month summer season. In addition, there are changes in TOU periods for Schedule EV. These are shown in Appendix G.

F. Electric Master Meter Discounts

This section presents PG&E's electric master meter discount proposals for Electric Multifamily Service (Schedule ES) and Electric Mobile Home Park Service (Schedule ET).[11] Under these rate schedules, electricity is delivered to a single master meter at a residential development, and the electricity is then delivered through a private sub-metered distribution system to individual tenants

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[10] PG&E filed Advice Letter 4830-E on April 25, 2016, to raise the cap to 60,000 customers until this issue can be resolved in the 2017 GRC Phase II.

[11] This 2017 GRC Phase II Application includes only PG&E's electric master meter proposals. Consistent with a prior Commission ruling, PG&E will continue to submit its gas master meter testimony in its BCAP. (See January 10, 2005 Administrative Law Judge Ruling Granting WMA Motion to Consider Gas Master Meter Discount Issues in Application 04-07-044 and Modifying Scoping Memo in Application 04-07-044.)

in mobile home parks (MHP) (Schedule ET) or other multifamily residential accommodations (Schedule ES). PG&E's end-use customers on the master meter schedules are the owners of the master-metered MHP or other master-metered multifamily residential developments such as apartment buildings or apartment complexes. The owners taking service from PG&E under these master meter rate schedules receive a discount to compensate them for costs that the utility avoids because they sub-metered the individual tenant spaces rather than having the utility directly serve those tenants. These rate schedules have been closed to new customers since January 1, 1997.

The master meter discount methodology proposed in this application follows the methodology adopted in D.11-12-053[12] and the direction pursuant to guidance in D.04-04-043 and D.04-11-033. The current Master Meter discounts were set in D.15-08-005, PG&E's 2014 GRC Phase II, adopting an all-party settlement.

PG&E's proposed rates under this methodology are a net discount of $1.18 for Schedule ET, and a net discount of $0.76 for Schedule ES, per space per month.

1. Marginal Cost Master Meter Discount Methodology

In the 2003 GRC Phase II, PG&E, as part of its April 26, 2005, testimony,[13] put forward a marginal cost-based approach for calculating the master meter discount, as opposed to the sampling method presented by PG&E in previous GRCs. Discounts calculated using this method were ultimately adopted in the settlement approved in D.05-11-005 and this same value was again adopted in D.07-09-004 in PG&E's 2007 GRC. In PG&E's 2011 GRC Phase II, the Company performed a thorough review of its master meter discount methodology and carefully evaluated proposals

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12 The Western Manufactured Housing Communities Association's (WMA) timely filed a Petition to Modify and Application for Rehearing of Decision 11-12-053, both of which the CPUC denied. (*See* D.12-10-004 and D.12-09-046, respectively.) On September 21, 2012, WMA timely filed with the Court a Petition for Writ of Review. The CPUC, as well as The Utility Reform Network (TURN) and PG&E all opposed WMA's Petition, which was denied by the District Court of Appeal of the State of California in and for the First Appellate District, Division Three (NO. A136617).

13 2003 GRC Phase II, A.04-06-024, Exhibit (PG&E-10), Chapter 2B, "Residential Rates: Electric Master Meter Discounts."

presented by TURN and WMA. In response to these proposals, PG&E further refined its methodology with parties agreeing to some but not all of PG&E's proposals. PG&E reached a settlement for the Schedule ES master meter discount that was approved by the Commission in D.11-12-053. No settlement could be reached, however, for the master meter MHP discount in Schedule ET, and the methodology was fully litigated. In D.11-12-053, the Commission adopted PG&E's MHP master meter discount methodology, which was consistent with the guidance provided in D.04-04-043 and D.04-11-033 (the 2004 Decisions).[14]

In reaching its decision on MHP master meter methodology in PG&E's 2011 GRC Phase II, the Commission resolved several highly-contested issues that had been the subject of debate for some time. In resolving these issues, the CPUC decided: (1) to include replacement costs through application of the Real Economic Carrying Cost (RECC) to new connection equipment costs; (2) to exclude any Equal Percentage of Marginal Cost factors; (3) to consider new connection costs to properly be the costs as capped by PG&E's line extension allowances under Rules 15 and 16 with application of the rental method; and (4) that PG&E's multi-family residential costs are a reasonable proxy for the average avoided costs to otherwise directly serve tenants in master metered MHPs. In this proceeding, PG&E proposes to continue using that same methodology consistent with what the CPUC adopted in D.11-12-056.

2. Diversity Benefit Adjustment

a. Background

The Commission defines the diversity benefit adjustment as follows:

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[14] The 2004 D.04-04-043 and D.04-11-033, were the decisions arising from Phase I and Phase II, respectively, of the MHP Sub-metering Discount R.03-03-017/I.03-03-018. These 2004 Decisions identified categories of costs avoided by electric and natural gas utilities when MHP tenants are served by a master meter owner. Specifically, D.04-04-043 "identified the categories of costs the electric and natural gas utilities incur when directly serving MHP tenants that are avoided by the utilities when the MHP is served through a distribution system owned and operated by the MHP owner." (See D.04-11-033, p. 2, *citing* D.04-04-043.) These 2004 decisions allowed utilities to use a marginal cost methodology for master meter discount calculations in addition to the prior existing method using a statistically valid random sample of directly served MHPs in a utility's service area.

> The diversity benefit adjustment reduces the discount paid to the MHP owner to account for the fact that while the MHP owner receives a full baseline allowance for each space, some tenants use less than the baseline allowance, and some spaces may be vacant. (D.04-11-033, mimeo, p. 10.)

In its 2003 GRC Phase II settlement, PG&E agreed to work with TURN and WMA to conduct a study to calculate the diversity benefit adjustment. This study was still in progress as of the filing date for PG&E's 2007 GRC Phase II Application. In the 2007 GRC Phase II settlement agreement, PG&E agreed to submit the study by August 1, 2007. After submitting the study, PG&E agreed to certain refinements proposed by WMA. The resulting diversity benefit adjustment was $4.24 per space per month, but was not implemented in the 2007 GRC Phase II due to the delay in submitting the study.

PG&E updated the diversity benefit adjustment study as part of its 2011 GRC Phase II showing. PG&E updated that same model and database with the proposed Schedule E-1 rates and baseline quantities. Ultimately, pursuant to D.11-12-053 and Advice 3896-E-B, a Schedule ET diversity benefit adjustment of $5.20 per space per month was implemented in rates effective January 1, 2012. Further, based on the adopted 58 percent ratio for the relationship between the Schedule ES and Schedule ET diversity benefit adjustments, a multifamily apartment building Schedule ES diversity benefit adjustment of $3.02 per space per month was implemented in rates effective January 1, 2012. Although WMA contested many aspects of PG&E's proposed net master meter discount for Schedule ET, WMA generally agreed with PG&E's diversity benefit adjustment proposals, as did TURN.

Similarly, in PG&E's 2014 GRC Phase II proceeding, pursuant to D.15-08-005, and as implemented on January 1, 2016 through Advice 4696-E-A, the resulting Schedule ET DBA was $4.92 per space per month, and for Schedule ES was $2.86 per space per month, based on tenant usage from 2011 and 2012. The update for subsequent residential rate reform implementation on March 1, 2016 provided values for the Schedule ET DBA of $5.39 and Schedule ES DBA of $3.13 through Advice 4795-E and 4805-E/A. In D.15-08-005, the CPUC specified that the Schedule ES/ET DBA values were to be updated with each major implementation of residential rate reform.

b. PG&E's Proposed Diversity Benefit Adjustment

For this 2017 GRC Phase II proceeding, PG&E has once again updated the prior Schedule ET diversity benefit adjustment study, using the data base and all analytical methods authorized and adopted by the CPUC in the prior two GRC Phase II proceedings. The sample of 206 directly served MHPs comprised of some 13,400 tenant units has been rerun based on updated more recent 2014 and 2015 calendar year recorded usage. As before, the model has been updated to re-tier all recorded usage at the proposed 2017 GRC Phase II Schedule E-1 rates and baseline quantities. The main enhancement to the DBA analysis in this proceeding has been to incorporate the new residential Delivery Only Minimum Bill adopted in D.15-07-001 that became effective March 1, 2016 into the analysis of excess revenues that accrue to park operators on a system average basis.

The resulting MHP diversity benefit adjustments are $5.73 per space per month for Schedule ET, and $3.32 for Schedule ES.[15] The Schedule ET proposed value has increased compared to the currently-adopted $5.39 value per Advice 4795-E. PG&E attributes the increase to reductions in proposed baseline quantities, changes in tenant usage in 2014 and 2015 compared to 2011 and 2012 and the new residential Delivery Only Minimum Bill.

The Schedule ET diversity benefit study submitted in this exhibit was based on a mutually agreed sample of 206 electric MHPs developed in 2007 where all tenant spaces and common area accounts are directly individually metered by PG&E. PG&E proposes to continue to set the Schedule ES diversity benefit adjustment at a ratio based on values calculated from random samples of MHPs and multi-family

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15 PG&E has calculated the ET DBA value under both a 4-month summer, and a 6-month summer season, with associated rates and baseline quantities. The proposed ET DBA value above is the average of the two scenarios, of $5.80 for the 6 month summer, and $5.66 for the 4-month summer. Since the two results are so close, upon implementation, PG&E proposes to simply update the ET DBA on then current 6-month summer rates, to avoid needing any future updates within the 2017 GRC Phase II cycle.

apartment buildings in the 2003 GRC Phase II, which was the basis for the 58 percent ratio adopted in D.11-12-053 and D.15-08-005. Those prior 2003 GRC Phase II proposed values were $3.48 per space for Schedule ET and $2.01 for Schedule ES.[16] Applying this 58 percent ratio to the proposed Schedule ET diversity benefit adjustment of $5.73 produces a proposed Schedule ES diversity benefit adjustment of $3.32 per space per month. These proposed values for the Schedule ES and ET diversity benefit adjustments are reflected below in the net master meter discounts proposed in Table 4-20.

These proposed diversity benefit adjustment values are illustrative only, and are to be updated upon GRC Phase II implementation based upon the rates and revenue requirements in effect upon implementation.[17] PG&E proposes that the DBA be set initially, and subsequently remain unchanged throughout the 2017 GRC Phase II cycle.

3. Proposed Master Meter Discounts

Table 4-20 shows the present and proposed master meter discounts, including PG&E's resulting proposed base discounts, diversity benefits and line loss adjustment.[18] PG&E's proposed base master meter discounts are summarized in Table 4-21 and Table 4-22 for Schedules ET and ES, respectively.

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[16] The adopted 58 percent figure equals $2.01 divided by $3.48.

[17] See discussion in D.11-12-053, mimeo, p. 41, as well as Conclusion of Law 12, and Ordering Paragraph 13, of that decision.

[18] The line loss adjustment adds to the base discount to compensate the master meter customer for usage at the master meter that is lost when distributed to the tenant spaces. Similar to the proposal for the DBA, the line loss adjustment is calculated using per-tenant tired usage for 4-month and 6-month summer seasons. The respective monthly line loss adjustments under these two scenarios are $2.17178 and $2.17865, respectively. The illustrative Schedule ET master meter discount is calculated using a line loss adjustment value of $2.17521, the average of the two scenario values.

TABLE 4-20
PRESENT AND PROPOSED ELECTRIC MASTER METER DISCOUNTS
(PER MONTH, PER UNIT)

		Current Discount(a)		Proposed 2017 Test Year Discount				
Line No.	Rate Schedule	Net Discount	Daily Equivalent	Base Discount	Diversity Benefit (-) Adjustment	Line Loss (+) Adjustment	Net Discount	Daily Equivalent
1	ET – Mobilehome Park Service	$5.48	$0.18004	$4.73	$5.73	$2.18	$1.18	$0.03861
2	ES – Multifamily Service	$1.54	$0.05075	$4.08	$3.32	–	$0.76	$0.02485

(a) Electric Master Meter Discount Rate in effect June 1, 2016.

TABLE 4-21
SCHEDULE ET – MASTER METER DISCOUNTS

Line No.	Schedule ET Master Meter Discount	Costs for Tenant Meter	Costs for Master Meter[(a)]
1	Transformer	$315.17	$13,464.16
2	Service	202.43	16,572.52
3	Meter	164.94	1,899.38
4	Transformer/Service/Meter (TSM) Equip. Cost	$682.53	$31,936.06
5	RECC	7.45%	7.45%
6	Annualized Connection Equipment Cost — Finance, Tax, Ins. & Depr.	$50.87	$2,380.00
7	Test Year Secondary Dist. ($/kW-Yr)	$1.41	
8	<u>Test Year Ongoing Costs Per Residential Unit</u>		
9	Meter Services	$11.69	$19.34
10	Transformer Maintenance	0.61	25.88
11	Service Maintenance	1.53	125.24
12	Meter Reading	4.74	11.78
13	Billing & Collections	14.98	14.22
14	Other Account 903 (Adjusted)	10.71	20.64
15	Total Ongoing Costs Per Residential Unit	$44.25	$217.11
16	Total Connection Cost	$96.52	$2,597.12
17	Average Number of Residential Units		65
18	Master Meter Connection Cost Per Residential Unit		$39.96
19	Net Marginal Connection Cost Per Residential Unit	$56.57	
20	Uncollectibles Factor	0.3386%	
21	Uncollectibles	0.19	
22	Net Base Discount Per Residential Unit — Annual	$56.76	
23	Base Master Meter Discount Per Residential Unit - Monthly	$4.72995	
24	Diversity Benefit Adjustment (Illustrative)	$5.73000	
25	Line Loss Adjustment	$2.17521	
26	Net Discount (Monthly) (Illustrative)	$1.18	
27	Net Discount (Daily) (Illustrative)	$0.03861	

(a) Master Meter costs uses ML&P-S proxy meter for connection; SL&P proxy meter for ongoing costs except transformer and service maintenance; transformer and service maintenance calculated for Medium L&P proxy connection.

TABLE 4-22
SCHEDULE ES – MASTER METER DISCOUNTS

Line No.	Schedule ES Master Meter Discount	Costs for Tenant Meter	Costs for Master Meter[(a)]
1	Transformer	$–	$–
2	Service	–	–
3	Meter	164.94	1,899.38
4	Transformer/Service/Meter (TSM) Equip. Cost	$164.94	$1,899.38
5	RECC	7.45%	7.45%
6	Annualized Connection Equipment Cost — Finance, Tax, Ins. & Depr.	$12.29	$141.55
7	Test Year Secondary Dist. ($/kW-Yr)	$–	
8	<u>Test Year Ongoing Costs Per Residential Unit</u>		
9	Meter Services	$11.69	$19.34
10	Transformer Maintenance	–	–
11	Service Maintenance	–	–
12	Meter Reading	4.74	11.78
13	Billing & Collections	14.98	14.22
14	Other Account 903 (Adjusted)	10.71	20.64
15	Total Ongoing Costs Per Residential Unit	$42.11	$65.99
16	Total Connection Cost	$54.40	$207.54
17	Average Number of Residential Units	–	37
18	Master Meter Connection Cost Per Residential Unit	–	$5.61
19	Net Marginal Connection Cost Per Residential Unit	$48.79	
20	Uncollectibles Factor	0.3386%	
21	Uncollectibles	$0.17	
22	Net Base Discount Per Residential Unit — Annual	$48.96	
23	Base Master Meter Discount Per Residential Unit — Monthly	$4.07978	
24	Diversity Benefit Adjustment (Illustrative)	$3.32340	
25	Line Loss Adjustment	$–	
26	Net Discount (Monthly) (Illustrative)	$0.75638	
27	Net Discount (Daily) (Illustrative)	$0.02485	

(a) Master Meter costs uses ML&P-S proxy meter for connection; SL&P proxy meter for ongoing costs except transformer and service maintenance; transformer and service maintenance calculated for Medium L&P proxy connection.

G. Conclusion

The Commission should adopt PG&E's residential rate design proposals to move all of its rate schedules closer to cost-based rates and increase equity among all of its customers. The proposed changes to baseline quantities, CARE

Tier 3 rates, collapsed non-CARE Tier 3 and 4 rate, and basic service fees for CARE and non-CARE customers on most optional rates will help reduce PG&E's high upper tier rates to help address the current rate imbalances.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

SMALL LIGHT AND POWER RATE DESIGN

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SMALL LIGHT AND POWER RATE DESIGN

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) proposes rates for the Small Light and Power (SL&P) customer class to be implemented pursuant to a decision in Phase II of its 2017 General Rate Case (GRC). These proposals include changes to distribution, Public Purpose Program (PPP) and generation rate components.[1] A key objective of PG&E's proposals for rates for the SL&P customer class is to use marginal cost relationships to set distribution and generation rates, balanced with other objectives such as rate stability.[2]

PG&E's SL&P proposals in this proceeding are described in the following testimony and include:

- Revise rates for the new seasons and time-of-use (TOU) periods;[3]
- Revise the SL&P customer charges to better reflect cost;
- Set the Schedule A-1 TOU price differentials to fully reflect the generation marginal cost differentials by TOU period;
- Adjust the Schedule A-6 TOU price differentials to equal the generation and primary distribution capacity marginal cost differentials;
- Maintain the boundary between the SL&P and Medium Light and Power (ML&P) classes at 75 kilowatts (kW); and
- Establish an optional TOU rate, A1-DMD, with a maximum (or non-coincident) demand charge and TOU price differentials set equal to the marginal generation costs.

This chapter focuses on PG&E's distribution, generation and total rate design and other proposals for the SL&P customer class that traditionally fall within the scope of GRC Phase II proceedings.[4] Table 5-1 lists the rate

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1 See Exhibit (PG&E-1), Chapter 1 for description.

2 See Exhibit (PG&E-1), Chapter 1 for discussion.

3 See Exhibit (PG&E-2), Chapter 12.

4 PPP rates for the SL&P customer class are designed in accordance with the guidelines described in Exhibit (PG&E-1), Chapter 1.

schedules currently applicable to the SL&P customer class, with information about the accounts and sales under each schedule. TOU rates are mandatory for customers served on Schedules A-1 and A-6 with at least 12 months of interval data.

TABLE 5-1
SL&P ACCOUNTS AND SALES
2015 RECORDED

Line No.	Schedule	Description	2015 Accounts	Total Annual Sales (GWH)	Average Sales Per Customer (kWh)
1	A-1	Non-TOU	74,000	1,420	19,100
2	A-1 TOU	TOU	355,000	5,400	15,200
3	A-6	TOU	27,000	1,390	52,300
4	A-15	Direct Current Service	400	0.4	1,000
5	TC-1	Traffic Control	12,000	40	3,000
6	Total		468,400	8,250	18,000

The remainder of this testimony is organized as follows:

- Section B – Customer and Energy Charges
- Section C – Boundary Between the SL&P and ML&P Classes
- Section D – Optional TOU Rate Schedule With Demand Charges
- Section E – Conclusion

Appendix B, “Present and Proposed Rates” of this exhibit, contains PG&E’s present and proposed illustrative total and unbundled rates for the SL&P customer class. Appendix G, “Illustrative Bill Impacts of Present Versus Proposed Total Rates” of this exhibit, presents the bill comparison impacts of PG&E’s proposed rates.

B. Customer and Energy Charges

As discussed in Chapter 1, “Revenue Allocation and Rate Design Policy,” of this exhibit, PG&E continues to design revenue-neutral rates for Schedules A-1, A-6 and A-15. Schedule A-15 rates are set equal to rates on Schedule A-1 with the exception of the A-15 facilities charge.

1. Customer Charges

PG&E proposes to move toward full cost-based customer charges to the extent reasonable with regard to bill impacts. There is a wide gap between current prices and full, cost based customer charges.[5] Consequently, PG&E proposes to increase the Schedule A-1, A-6 and A-15 customer charges for single-phase and polyphase service customers, as well as the customer charge for Schedule TC-1. The proposed charges are shown in Table 5-2. Even as revised, the proposed customer charges fall far short of both the full cost based charge and the marginal cost.[6]

TABLE 5-2
PROPOSED SL&P CUSTOMER CHARGES

Line No.	Service	Customers	Current	Proposed	Marginal Cost	Full Cost
1	Single-Phase	252,400	$10.00	$15.00	$36	$68
2	Polyphase	204,000	$20.00	$40.00	$93	$173
3	Traffic Control	12,000	$10.00	$20.00	$128	$237

The proposed increases for single-phase service are modest and supported by the marginal cost data. The more substantial increases for polyphase and traffic control are reasonable, given how far from full marginal costs they currently are. PG&E will also revise these customer charges for changes in rates required to implement changes in distribution revenue.[7]

2. Energy Charges

Schedule A-1 includes seasonal energy charges determined in accordance with guidance set forth in Chapter 1, "Revenue Allocation and Rate Design Policy," of this exhibit. PG&E proposes that seasonal distribution energy charges be based on primary distribution marginal cost revenue differences so that non-peak related revenues and residual marginal customer costs not collected in the proposed customer charge are collected on annual equal-cents-per kilowatt-hour (kWh) basis. The residual revenue for determining Schedule A-1 and A-15 energy charges was

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5 Full cost based customer charges are shown in Table 5-2, and include the marginal cost as well as the Equal Percent of Marginal Cost multiplier.

6 The equivalent daily charge for billing and presentation in tariffs is calculated as 12 times the monthly charge, divided by 365.25 days per year.

7 As noted in Exhibit (PG&E-8), Chapter 1.

calculated by subtracting Schedules A-1 and A-15 customer charges, the A-15 facilities charge, and Schedule A-6 energy and customer charge from the SL&P total revenue. As a result, the differential between the Schedule A-1 summer and winter seasonal rates is approximately equal to the seasonal difference in marginal costs. Finally, Schedule A-1's seasonal energy charges are designed for the entire population of A-1, A-6, and A-15 customers.

Schedule A-1 TOU, the default schedule for the SL&P class, has five TOU periods identical to TOU Schedule A-6. Unlike A-6, its current TOU price differentials are much narrower and reflect only generation time differentiation. PG&E proposes to increase the current Schedule A-1 TOU rate differential from five cents per kWh differential (from summer on peak to summer off peak) to seven cents per kWh. This change will nearly fully reflect the differences in marginal generation costs between TOU periods.

Proposed A-1 TOU rates are shown in Table 5-3. As a final step in rate design, winter energy rates are adjusted to provide for the super off-peak period[8] to develop final winter energy prices for peak off-peak and super off-peak periods.[9] PG&E proposes that the TOU differentials as set forth in the illustrative rates for A-1 TOU be retained when changing rates for revenue requirement changes subsequent to a decision in this proceeding.

TABLE 5-3
CURRENT AND PROPOSED A-1 TOU ENERGY RATES

Line No.	TOU	October 2016 ($/kWh)	PG&E Proposed ($/kWh)
1	Summer Peak	$0.26	$0.29
2	Summer Part-Peak	$0.24	$0.23
3	Summer Off-Peak	$0.21	$0.22
4	Winter Part-Peak/Peak	$0.22	$0.21
5	Winter Off-Peak	$0.20	$0.19

TOU energy charges for Schedule A-6 were designed using combined A-1, A-6, and A-15 energy usage. Seasonal revenue requirements were set

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8 See Exhibit (PG&E-8), Chapter 1 for description.

9 See Exhibit (PG&E-8), Appendix B for final rates with the super off-peak period.

by first calculating the average seasonal energy rates for the combined A-1, A-6 and A-15 population (total revenue requirement, less the customer charge, divided by total kWh), then multiplying each seasonal rate by A-6 summer and winter energy usages.

Schedule A-6 generation rates are determined based on the marginal differences between TOU periods in the same manner described above for Schedule A-1 TOU. Schedule A-6 distribution rates utilize the primary distribution marginal capacity costs by TOU period to establish distribution TOU rates. Any off-peak primary distribution marginal cost and any residual distribution revenue are added to each TOU rate on an equal cent per kWh basis. Finally, PG&E proposes to set distribution peak prices and partial peak prices in the summer at the same level in recognition that PG&E's distribution peak occurs over a broader range of hours than the generation system. Proposed A-6 rates are shown in Table 5-4.

As a final step in rate design, winter energy rates are adjusted to provide for the super off-peak period[10] to develop final winter energy prices for peak, off-peak and super off-peak periods.[11] Just as with Schedule A-1 TOU, PG&E proposes that the TOU differentials as set forth in the illustrative rates for A-6 be retained when changing rates for revenue requirement changes subsequent to a decision in this proceeding.

TABLE 5-4
CURRENT AND PROPOSED A-6 TOU ENERGY RATES

Line No.	TOU	October 2016 ($/kWh)	Proposed Rates ($/kWh)
1	Summer Peak	$0.55	$0.30
2	Summer Part-Peak	$0.25	$0.24
3	Summer Off-Peak	$0.18	$0.19
4	Winter Part-Peak/Peak	$0.20	$0.21
5	Winter Off-Peak	$0.18	$0.19

10 See Exhibit (PG&E-8) Chapter 1 for description.

11 See Exhibit (PG&E-8), Appendix B for final proposed rates with the super off-peak period

C. Boundary Between the SL&P and ML&P Classes

PG&E's boundary between the SL&P and ML&P classes is currently 75 kW. This was approved by Decision 15-08-005 for the 2014 GRC Phase II proceeding. PG&E is proposing to retain this boundary in this 2017 GRC Phase II proceeding.

D. Optional TOU Rate Schedule With Demand Charges

PG&E is proposing an optional TOU rate schedule with demand charges to enable those customers who are less costly to serve to: (1) lower their bills relatively to what they pay now; and (2) provide a further incentive to lower overall demand. Customers could also lower their bills by installing battery storage technology that would enable them to store power when it is lower-priced and use the stored power when electricity is more expensive, as well as to lower maximum demand charges. Schedule A1-DMD will have the same price differentials between TOU periods as non-demand Schedule A-1, but all energy rates will be approximately 5.5 cents to 6.0 cents per kWh lower to reflect the approximate $13.50 per kW maximum demand charge on monthly non-coincident demands.

E. Conclusion

In this chapter, PG&E has summarized its proposals for rate design for the SL&P customer class in this 2017 GRC Phase II proceeding. PG&E requests that the Commission approve the proposals set forth in this chapter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

MEDIUM AND LARGE LIGHT AND POWER RATE DESIGN

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MEDIUM AND LARGE LIGHT AND POWER RATE DESIGN

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
MEDIUM AND LARGE LIGHT AND POWER RATE DESIGN

A. Introduction

In this chapter Pacific Gas and Electric Company (PG&E) proposes rates for the Medium and Large Light and Power (MLLP) customer class to be implemented pursuant to a decision in Phase II of its 2017 General Rate Case (GRC). As described in Chapter 1, "Revenue Allocation and Rate Design Policy" of this exhibit, these proposals include changes to distribution, public purpose program (PPP) and generation rate components. As discussed in Chapter 1 of this exhibit, a key objective in PG&E's MLLP rate proposal is to use marginal cost relationships to set distribution and generation rates, balanced with other objectives such as rate stability.

PG&E's MLLP proposals in this proceeding are described in the following testimony and include:

- Revise rates in accordance with the new seasons and time-of-use (TOU) periods recommended in Chapter 12 of Exhibit 9.
- Revise customer charges to better reflect cost of service.
- Adjust all MLLP energy and demand charges to better reflect the marginal generation and marginal primary distribution cost differences by TOU period.
- Set the maximum demand charge on Schedule A-10 at the same level in the summer and the winter.
- Eliminate the Schedule A-6 solar pilot for customers over 500 kilowatt (kW) that would otherwise be served on Schedule E-19.

This chapter focuses on PG&E's distribution, generation and total rate design and other proposals for the MLLP rate design classes.[1] Table 6-1 lists the rate schedules currently applicable to the MLLP customer classes, with information about the accounts and sales under each schedule. PG&E's current MLLP rate schedules consist of Schedules A-10, A-10 TOU, E-19 Voluntary (V), E-37, E-19 and E-20. Schedule A-10 TOU currently differs from the regular

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1 PPP rates for the MLLP class are designed in accordance with the guidelines described in Chapter 1 of this exhibit.

Schedule A-10 only in that Schedule A-10 TOU includes TOU differentiation of generation energy charges.

Schedule E-20 applies to customers with demand above 1,000 kW, Schedule E-19 Mandatory (M) applies to customers with demand above 500 kW. Schedules A-10, A-10 TOU or E-19 Voluntary are available to customers with demand less than 500 kW. Pursuant to D.15-08-005, Schedule E-37 will be eliminated beginning November 1, 2017, for customers with 12 months of interval data. Customers on Schedule E-37 will be moved to an applicable commercial or industrial rate schedule. TOU rates are mandatory for all commercial and industrial customers with at least 12 months of interval data.

TABLE 6-1
MEDIUM AND LARGE LIGHT AND POWER
RECORDED 2015

Line No.	Current PG&E	Average 2015 Accounts	Annual Sales (GWh)	Average 2015 Annual kWh Per Customer
1	Medium LP			
2	A-10	14,253	2,692	188,900
3	A-10 TOU	31,152	6,538	209,900
4	E-19 Voluntary	22,243	8,911	400,600
5	E-19 Mandatory	1,633	4,664	2,855,900
6	E-37	451	721	1,577,400
7	Large LP			
8	E-20	1,121	15,581	13,899,000
9	Total	70,853	39,107	551,946

The remainder of this chapter is organized as follows:

- Section B – Medium Light and Power (MLP)
- Section C – Large Light and Power (LLP)
- Section D – Schedule A-6 Solar Pilot for Customers Over 500 kW
- Section E – Conclusion

Appendix B, “Present and Proposed Rates,” of this exhibit, contains PG&E’s present and proposed illustrative total and unbundled rates for the MLLP customer classes. Appendix G, “Illustrative Bill Impacts of Present Versus Proposed Total Rates,” of this exhibit, presents the bill comparison impacts of PG&E’s proposed MLLP rates.

B. Medium Light and Power

1. Customer Charge for Schedules A-10 and E-19V

PG&E proposes to retain the current customer charge for Schedules A-10, A-10 TOU and E-19V.[2] The current charge is $140 per month, billed on a daily equivalent basis. While the current customer charge for Schedule A-10 and E-19V falls well below the level of full cost, PG&E believes the current level of recovery is adequate when compared to the proposed customer charge levels for Schedules A-1 and A-6 (which even as proposed only recovers about 20 percent of full cost). Though the fully cost-based customer charge at the primary voltage would be even higher, there are relatively few primary or transmission Schedule A-10 or E-19V customers. Accordingly, PG&E proposes to continue to set the customer charge for these customers at the same level by voltage.

Finally, as proposed in Chapter 1 of this exhibit, PG&E proposes to increase the customer charge for Schedules A-10 and E-19V together with distribution demand and energy charges when distribution rates are revised to collect changes to distribution revenue.

2. Demand and Energy Charges for Schedule A-10

The total demand charges for Schedule A-10 currently vary by season and voltage level but not by TOU period. In this proceeding, PG&E is proposing to set the demand charge in the summer and winter at the same level. PG&E's proposed demand charge is approximately equal to the demand charge currently assessed in the winter. The generation energy charges on Schedule A-10 TOU vary by TOU period. PG&E proposes to retain the TOU differentiation in energy charges at a level approximately equal to those in place today.

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[2] Other aspects of rate design for Schedule E-19V are addressed in the following sections on LLP rate design.

a. Distribution

PG&E proposes to differentiate the summer and winter distribution charges based on the primary distribution marginal cost.[3] In the past, PG&E has allocated 40 percent of the seasonal primary distribution marginal cost revenue through distribution demand charges and 60 percent through distribution energy charges. After customer charge revenues and primary distribution marginal costs were subtracted, PG&E assigned the remaining distribution revenue requirement on A-10 primary and secondary service at 40 percent to a flat annual maximum demand charge, and at 60 percent to a flat annual energy charge. In this proceeding, PG&E proposes to assign all seasonal primary distribution marginal cost revenue to energy charges by season. PG&E proposes to retain the seasonal distribution energy rate differentials (on an equal cents per kWh basis) for future distribution revenue requirement changes after a decision in this proceeding.

b. Generation

For generation, PG&E proposes to base the difference between summer and winter generation revenue based on the difference in generation marginal cost revenue. Rather than collect some A-10 generation demand cost in a summer maximum demand charge as has been PG&E's past practice, in this proceeding, PG&E proposes to collect all A-10 generation revenue in generation energy charges.

Differentials between on, part and off peak periods are based on the differences between marginal generation energy costs. Additional differentiation in time differentiated generation rates is attained by assigning the marginal generation capacity costs to the peak and partial peak periods. Like current charges, proposed Schedule A-10 energy charges are differentiated by voltage level.

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[3] Only the primary distribution portion of marginal distribution capacity costs are allocated on the basis of peak capacity allocation factors to reflect load diversity on capacity infrastructure facilities, while the secondary distribution and new business primary portion of marginal distribution capacity costs are allocated on the basis of final line transformer loads to reflect non-coincident load impacts on capacity infrastructure needs.

This results in a differential between summer on and off-peak energy rates of approximately 7 to 9 cents per kWh, which is similar to the differential that is in rates today. As a final step, winter energy rates are then adjusted to provide for the super off peak period as described in Chapter 1 of this exhibit to develop final winter energy rates for the peak, off peak and super off peak periods. Like Schedules A-6 and A-1 TOU, these TOU price and seasonal differentials on a cents per kWh basis will be retained when changing rates for revenue requirement changes subsequent to a decision in this proceeding.

C. Large Light and Power

PG&E's current LLP class encompasses all non-agricultural accounts with maximum demands over 1,000 kW. This includes Schedule E-20. Due to the similarity in rate design between Schedule E-19 and E-20, this section also addresses Schedule E-19 rate design, including voluntary Schedule E-19V. Schedule E-19 is a mandatory TOU rate for accounts with maximum demands between 500 and 1,000 kW. Schedule E-19V is available on a voluntary basis to accounts below 500 kW. Schedule E-20 is a mandatory TOU rate for accounts with maximum demands above 1,000 kW.[4] Schedule E-37 may include customers over 500 or 1,000 kW, but will be eliminated beginning November 1, 2017.

1. Customer Charges

PG&E's proposed customer charges for Schedule E-19 and E-20 are compared with current customer charges and fully cost based customer charges in Table 6-2, below. As indicated in the table, customer charges at transmission voltage are set too high relative to cost. Accordingly, PG&E proposes to reduce the level of these charges to better reflect cost. At primary and secondary service, PG&E proposes adjustments to customer charges to better reflect cost, but limits increases to no more than 20 percent. Finally, to retain the current relationship of charges at primary and secondary service voltages, PG&E has limited its adjustments so that the customer charge for primary service is greater than, or equal to, the

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4 The incentives to participate in the Base Interruptible Program will continue to be considered in Demand Response proceedings consistent with current practice.

customer charge for secondary voltage service on Schedule E-20. Finally, as proposed in Chapter 1 of this exhibit, PG&E proposes to increase customer charges for Schedules E-19 and E-20 together with distribution demand and energy charges when distribution rates are revised to collect changes to distribution revenue.

TABLE 6-2
MEDIUM AND LARGE LIGHT AND POWER
PROPOSED CUSTOMER CHARGE LEVELS

Line No.		Current	Proposed	Marginal Cost	Full Cost
1	A-10/E-19V S	$140	$140	$225	$418
2	E-19 T	1,800	1,400	733	1,362
3	E 19 P	1,000	1,100	614	1,142
4	E 19 S	600	720	699	1,299
5	E-20 T	2,000	1,500	832	1,546
6	E-20 P	1,500	1,300	653	1,214
7	E-20 S	$1,200	$1,300	$767	$1,426

2. Demand and Energy Charges

a. Distribution

After customer charge revenues are subtracted, PG&E proposes to collect 100 percent of the remaining seasonal distribution revenue requirement through distribution demand charges. As with Schedule A-10, the seasonal distribution revenues are differentiated by the marginal primary capacity cost difference between summer and winter. All remaining costs are used to design a maximum distribution demand charge that is the same in both seasons.

For the TOU differentiation of Schedule E-19 and E-20 distribution demand charges within season, PG&E recommends using the primary marginal cost revenue by TOU period to set the TOU price differentials. PG&E has set the summer distribution peak and partial peak demand charge at the same level in recognition that PG&E's distribution peak occurs over a much broader range of hours than the generation system. In addition, PG&E has proposed to set distribution TOU demand charges at the same level for primary and secondary service on Schedule E-20 in order to retain appropriate rate relationships between these service options. PG&E also proposes to retain seasonal and TOU distribution demand and energy component rate changes on an equal cents per kWh basis for future distribution revenue requirement changes after a decision in this proceeding. Finally, PG&E has discontinued use of TOU distribution demand charges in the winter because this rate value is quite low today and continues to be low under the rate design for this proceeding.

b. Generation

In general, in designing generation rates, PG&E uses the marginal generation capacity cost to set the TOU demand charges, and uses the marginal generation energy costs to set the energy rates. To implement that design in the past, PG&E based TOU price differentials on 'scaled' generation marginal cost. That is, when used to set rates, the scaled marginal costs produced differences in TOU pricing that exceeded the marginal cost. In this proceeding, PG&E proposes TOU price differentials for energy and demand generation rates based only on the marginal differences by TOU period. This has the effect of reducing the time differentiation in both energy and demand charges.

As a final step, winter energy rates are then adjusted to provide for the super off peak period as described in Chapter 1 of this exhibit to develop final winter energy rates for the peak, off peak and super off peak periods. PG&E proposes to retain these seasonal and TOU price differentials on a cents per kWh basis when changing demand and energy charge rates for revenue requirement changes subsequent to a decision in this proceeding.

3. Power Factor Adjustments

PG&E proposes no revision to the power factor adjustment rate credit (or penalty) of $0.00005 per kWh for every percentage point above (or below) an 85 percent power factor, as adopted in Decisions (D.) 05-11-005, 07-09-004, 11-12-053 and 15-08-005.

4. Option R

PG&E has retained Option R of Schedules E-19 and E-20 in this proceeding, and has included illustrative rates with this filing. PG&E

proposes to continue the current rate design practices for these options where all generation demand charges are converted to energy rates and 75 percent of the distribution peak related charges are converted to energy rates.

D. Schedule A-6 Solar Option for Customers Over 500 kW

In D.07-09-004 of PG&E's 2007 GRC Phase II, a settlement was adopted to provide Schedule E-19 customers with a maximum demand between 500 kW and 999 kW the option to elect service on Schedule A-6 if a solar photovoltaic system was installed. Term D[5] contained the specific elements of this solar pilot program, capped at 20 megawatts (MW) of participating installed solar system output. These terms and conditions were codified into the Schedule A-6 tariff through the addition of the Special Condition titled "Solar Pilot Program."

In D.15-08-005, the Commission approved PG&E's proposal to close the program to new customers and grandfather this program for continued participation only by current participants. The Schedule A-6 Solar Pilot Program was capped at 20 MW, and is fully subscribed. In this proceeding, PG&E proposes to eliminate this pilot and require these customers to move to any otherwise applicable rate or rate option. As the CPUC explained in prior decisions, "for decades, the Commission has used demand charges to collect capacity-related costs, since doing so is consistent with cost-based rate design. Marginal distribution and generation capacity costs are measured in units of dollars per kW. Rate design based on marginal costs establishes demand charges (in units of dollars per kW) for these services. The rates applicable under Schedules A-10 and E-19 are closer to fully cost-based in this regard."[6]

E. Conclusion

In this chapter, PG&E has summarized its proposals for rate design for the MLLP customers in this 2017 GRC Phase II proceeding. PG&E requests that the Commission approve these proposals. Balanced with other objectives, PG&E's rate design proposals will achieve movement toward cost of service

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5 Term D is at pages 7 to 8 of Appendix G of D.07-09-004.

6 D.15-08-005, mimeo, p. 32. See also D.11-12-053, mimeo, p. 27, rejecting proposals by the Solar Alliance for expansion of the A-6 Solar Pilot.

targets by realigning demand versus energy, seasonal, and TOU ratios to reflect underlying distribution and generation marginal costs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

AGRICULTURAL RATE DESIGN

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CHAPTER 7
AGRICULTURAL RATE DESIGN

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E or the Company) proposes rates for the agricultural customer class to be implemented pursuant to a decision in Phase II of its 2017 General Rate Case (GRC). As described in Chapter 1, "Revenue Allocation and Rate Design Policy" of this exhibit, these proposals include changes to distribution, public purpose program (PPP) and generation rate components. As discussed in Chapter 1 of this exhibit, a key objective of PG&E's agricultural rate design proposal is to use marginal cost relationships to set distribution and generation rates, balanced with other objectives such as rate stability, understandability and simplicity.

The agricultural rate designs PG&E is proposing in this proceeding, covering approximately 89,000 agricultural customer accounts in total, are described in the following testimony. In summary, PG&E's key proposals are to:

- Revise rates to reflect the updated, cost-based seasons and Time-of-Use (TOU) periods recommended in Chapter 12 of Exhibit 9;
- Simplify agricultural rates by consolidating the current 13 rate schedules into 3 basic default rates, with 1 additional optional rate offering longer contiguous uninterrupted off-peak hours, as described in Table 7-2 below;
- Move all agricultural monthly customer charges toward full Equal Percent of Marginal Cost (EPMC) cost-based levels; and
- Move all agricultural energy and demand charges toward full cost levels subject to setting seasonal and TOU price differentials based on marginal cost.

This chapter focuses on PG&E's distribution, generation and total rate design and other proposals for the agricultural rate design classes.[1] Table 7-1 lists the rate schedules currently applicable to the agricultural customer class, with information about the accounts and sales under each schedule. PG&E's

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1 PPP rates for the agricultural class are designed in accordance with the guidelines described in Chapter 1 of this exhibit.

current agricultural rate schedules consist of Schedules AG-1A/B, AG-4A/B/C, AG-5A/B/C, AG-RA/B, AG-VA/B, and AG-ICE. The AG "A" designations apply to customers below 35 horsepower (hp), while the AG "B" or "C" designations apply to customers above 35 hp.

TOU rates are mandatory for all agricultural customers who have at least 12 months of interval data.

TABLE 7-1
CURRENT AGRICULTURAL ELECTRIC RATES
RECORDED 2015

Line No.	Current PG&E	Average Number of Accounts 2015	Description	Average Annual kWh Per Customer 2015
1	AG-1A	6,338	Small Non-TOU	7,788
2	AG-1B	3,452	Medium Non-TOU	39,736
3	AG-4A	34,716	Small 2-Period TOU < 35 hp	11,179
4	AG-4B	12,885	Medium 2-Period TOU > 35 hp	60,104
5	AG-4C	1,272	Medium 3-Period TOU > 35 hp	68,242
6	AG-5A	4,987	Small 2-Period TOU < 35 hp	28,913
7	AG-5B	16,378	Large 2-Period TOU > 35 hp	192,740
8	AG-5C	2,604	Large 3-Period TOU > 35 hp	941,196
9	AG-RA	1,817	Small Split-Week 2-Period TOU < 35 hp	17,273
10	AG-RB	674	Medium Split-Week 2-Period TOU > 35 hp	46,799
11	AG-VA	1,321	Small Short-Peak 2-Period TOU < 35 hp	14,957
12	AB-VB	350	Medium Short-Peak 2-Period TOU > 35 hp	55,189
13	AG-ICE	1,800	Diesel Pumping Conversion Rate	204,008
14	Total	88,594		86,426

The remainder of this chapter is organized as follows:

- Section B – Agricultural Collaborative Process
- Section C – Proposed Agricultural Rate Design
- Section D – Conclusion

Appendix B, "Present and Proposed Rates," of this exhibit, contains PG&E's present and proposed illustrative total and unbundled rates for the agricultural customer class. Appendix G, "Illustrative Bill Impacts of Present Versus Proposed Total Rates," of this exhibit, presents the bill comparison impacts of PG&E's proposed agricultural rates. Appendix E presents the report on the Agricultural Collaborative process.

B. Agricultural Collaborative Process

In the settlement approved by Decision (D.) 15-08-005, in PG&E's 2014 GRC Phase II proceeding, the California Public Utilities Commission (CPUC or Commission) adopted a recommendation by the Agricultural Rate Design Settling Parties[2] to conduct a Collaborative Agricultural Rate Design Process prior to filing PG&E's next GRC Phase II proceeding. The settlement provided, in part, the following:

> AG Settling Parties recognize that the effort of the collaborative process is to revise and improve the current AG Schedules and options for presentation in a future rate design proceeding such as the 2017 GRC II case, including consideration of changes to the time-of-use (TOU) periods. AG Settling Parties may submit mutually agreed to schedules or submit and respond to any recommendations made in such relevant future rate design proceeding. Under the timing set forth below, the AG Settling Parties agree to meet and conduct a collaborative process to explore whether a consensus can be achieved on what type of restructured rates and rate options should be considered in the 2017 GRC Phase II proceeding. This process may include selected focus groups including AG customers representing a diversity of sizes and types and geographic areas to see what insights can be gleaned to identify a more workable set of rates that can be consistent over the longer term.
>
> As recognized in the Joint Motion in this proceeding, consideration of the proposed restructuring or consolidation of agricultural rates will be pursued in a future rate design proceeding. Those same parties agreed that it was in the best interests of agricultural customers and would be more effective to develop new agricultural rate structures and rate options through a collaborative process where the different and varied agricultural interests can be presented and considered constructively.
>
> Parties anticipate continued cooperation to develop any restructured rates and provide herein general parameters to guide the collaborative process with the anticipation of development of rates that would be submitted jointly by the parties for consideration by the CPUC in a future proceeding.
>
> Development of rates will generally be conducted as follows:
>
> 1. A process to develop rates will commence no later than thirty days after a decision approving the AG Settlement Agreement.
> 2. Initial input from a broad range of PG&E's agricultural customers will be sought. AECA, CFBF and PG&E will each identify customers to be included for outreach in this process. Outreach will be targeted toward the following types of customers:
>   a. Customers on each of the agricultural rate schedules;

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[2] The Agricultural Settling Parties included the Agricultural Energy Consumers Association (AECA), the California Farm Bureau Federation (CFBF), the Energy Producers and Users Coalition, and PG&E. AECA, CFBF and PG&E are the participants in the collaborative rate design process.

b. Customers representing diverse operations in terms of crop, animal husbandry, agricultural processes and irrigation types; and

c. Customers who are geographically dispersed throughout the service territory.

d. Customers whose energy usage is impacted due to ongoing water scarcity.

3. To discuss possible parameters of restructured rates in-person meetings will be held with customers. Representatives from PG&E, CFBF and AECA will be included in such meetings. Three or four meetings with up to twelve invited customers at each meeting will be held at up to three locations throughout PG&E's service territory. Presentations for the meetings will be coordinated among the parties.

4. Subsequent to the initial meetings information, analyses, and proposals provided by the customers, AECA, CFBF, and PG&E will be compiled and assessed. Results of the review will then be presented to grower-customers for feedback about the implications of any proposed suite of rate structures.

5. The AG Settling Parties will carefully consider the discussions with customers and attempt to identify and agree upon the design and timing of any changes to PG&E's current agricultural rate structures to be proposed in future proceedings.

6. The AG Settling Parties intend that the collaborative process for development of the rates should conclude by October 2015 for purposes of input to the 2017 GRC Phase II proceeding.

The goal of the Collaborative process was to investigate and explore foundational rate design recommendations and areas of concern to all parties, largely by conducting focus groups with selected agricultural customers, followed by cooperative ongoing efforts and discussions to craft a mutually agreeable set of new proposed agricultural rates. Several customer meetings were held in 2015 as part of this process, as described in the Agricultural Rate Design Collaborative Report attached to this exhibit as Appendix E. In spite of the parties' good faith efforts to complete the envisioned Collaborative process, only the first three steps described in the settlement were completed. Many discussions occurred for steps four and five, but no agreements were reached. The increased collaboration with members of the agricultural community through the Collaborative also yielded conflicting rate design feedback from different types of agricultural customers. For example, a tension occurs because rate designs that favor large or high load factor customers may disadvantage smaller or low load factor customers, or vice versa. Generally, a desire was expressed for rates that are simpler with fewer moving parts.[3]

After holding the Collaborative meetings with customers, PG&E prepared the high level Report and provided it to all workshop participants. A slightly modified version is attached as Appendix E. Additionally, a series of conference calls were conducted to discuss the agricultural rate design going forward. During those discussions, PG&E provided draft rates for consideration by the parties. A refined version of those draft rates are provided as the proposed agricultural rates in this chapter. PG&E believes its proposals here address issues raised in collaborative discussions to the extent possible while retaining appropriate cost based price signals.[4] However, it is important to stress that, at the time PG&E needed to finalize its rate design proposals here, the Collaborative process had not been completed, and the consensus on agricultural rate design that had originally been contemplated was unfortunately not achieved for the June 30 filing deadline for this application. That is, the two major agricultural customer groups (the AECA and the CFBF) have not agreed that the rates proposed by PG&E are the type of restructured rates and rate options that they believe should be made available by the CPUC in the future.

PG&E hopes to continue discussions with AECA and CFBF to complete the collaborative process initially envisioned. In particular, while PG&E had provided sample rates to the parties during earlier discussions, the work had not progressed far enough to review and have discussions relating to the bill comparison results that PG&E is now able to present in Appendix G, "Illustrative Bill Impacts." PG&E hopes that this additional work and the further investigations and follow-up discussions that might now be conducted should

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3 As indicated in Appendix E, Section C, while customers were generally able to select the most beneficial rate schedule for their operations, they had difficulty knowing how to modify their operations to minimize their bill on their chosen rate schedule. In large part, this was because of a concern with regard to potentially conflicting price signals making it unclear whether to minimize their on-peak demand as opposed to their on-peak usage (e.g., Appendix E, Section D, Demand and Energy Price Signals in Conflict). A general desire for simpler rates is also implied in Appendix E, Section D, Manageability and Complexity.

4 For example, customers were interested in an all energy rate (See Appendix E, Section G). PG&E does not believe such a rate design would be appropriately cost-based.

allow the Collaborative process to continue in a productive way. Therefore, PG&E reserves the right to amend its proposals here to incorporate any consensus recommendations that might still emerge from ongoing discussions.

Thus, PG&E remains open to further cooperative rate design discussions, as well as potential revisions to its proposals, throughout this proceeding to achieve a consensus on rate design.

C. Proposed Agricultural Rate Design

PG&E's agricultural rate design proposals in this proceeding reflect a long-held desire by PG&E to simplify the large and confusing number of existing agricultural rate schedules. At the same time, PG&E is sensitive to the concerns and perspectives of the agricultural community when their rate options change.

Although PG&E was not able to agree to or incorporate all of the suggestions made during Collaborative discussions, PG&E's proposed new foundational agricultural rates have the following structural characteristics that respond to concerns raised by customers:

- Retain the four-period TOU structure with no partial peak period;
- Reduce the use of demand charges, including an option for larger customers with no TOU demand charge;
- Isolate TOU differentiation primarily to either demand or energy charges to provide clearer pricing incentives; and
- Add a demand charge limiter.

In addition, PG&E proposes a basic structure for a new agricultural TOU rate option that would allow longer hours of operation during an off-peak period, with staggered off-peak periods. As noted above, PG&E hopes that work can continue, with additional dialog building on the Collaborative efforts thus far. For now, PG&E respectfully requests that the CPUC, as well as the agricultural community, consider the merits of PG&E's proposals, and work constructively with PG&E to identify feasible and mutually acceptable refinements and reasonable modifications to these foundational rate proposals.

1. Summary

PG&E's proposal to simplify agricultural rates centers on the proposed rate schedule consolidation shown in Table 7-2. PG&E believes the resulting four rates promote an easier "best rate" selection by agricultural customers, by reducing the number of alternative rate options available for customers to select. PG&E provides an overview of each below:

a. New AG-A Rate

PG&E proposes to apply its proposed new Schedule AG-A to all customers under 35 hp, and specifically proposes to transition current Schedule AG-1A, RA, VA, 4A and 5A customers to this new AG-A tariff. If such a customer prefers it, they can instead opt to take service under Schedule AG-R, with staggered off-peak periods.

b. New AG-B Rate

PG&E's proposed new Schedules AG-B, along with new Schedule AG-C, would be available to all customers over 35 hp. Schedule AG-B, which is designed on a revenue-neutral basis, is generally designed for the lower load factor customers. Thus, all current Schedules AG-1B, RB, VB, 4B, and 4C customers would be transitioned, on a default, opt-out basis, to new Schedule AG-B, but may instead elect new Schedule AG-C if they prefer.[5] Alternatively, they can instead opt to take service under Schedule AG-R, with staggered off-peak periods (discussed in Section 2.c below).

c. New AG-C Rate

Like the new Schedule AG-B, PG&E's proposed new Schedule AG-C, would also be available to all customers over 35 hp. Schedule AG-C, which is designed on a revenue-neutral basis, is generally designed for higher load factor customers. This schedule will

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5 As a general rule, PG&E's current TOU Schedule AG-4 is designed for lower load factor customers with fewer operating hours. Schedule AG-4 contains lower demand charges, higher energy charges, and has less TOU differentiation. By contrast, TOU Schedule AG-5 is generally designed for higher load factor customers with more operating hours. Schedule AG-5 contains higher demand charges, lower energy charges, and has wider TOU differentiation.

PG&E's proposed new TOU Schedules AG-B and AG-C continue this basic tradeoff in rate schedule selection tied to load factor or number of pumping hours. Schedule AG-B is designed for lower load factor customers, while Schedule AG-C is designed for higher load factor customers who pump over 1,100 hours per year. Schedule AG-C concentrates the TOU price signal in a summer on-peak generation TOU demand charge, with commensurately lower and less differentiated summer TOU energy charges.

usually be the best rate for medium or large customers who pump over 1,100 hours per year. Thus, all customers currently on Schedules AG-5B and 5C would be transitioned, on a default opt-out basis, to the new Schedule AG-C, but may instead elect new Schedule AG-B if they prefer that rate. Alternatively, they can instead opt to take service under Schedule AG-R, with staggered off-peak periods (discussed in Section 2.c below).

d. Rate Selection

This proposed rate restructuring preserves the main 35 hp dividing line and reduces the current 1,500 hour per year AG-5B break-even pumping hours versus AG-4B to 1,100 hours per year, to make rate selection easier and less risky for customers.

The central elements of PG&E's agricultural rate design proposal are the agricultural rate simplification and consolidation depicted below in Table 7-2. All of the current rate schedules in each column of the top portion of Table 7-2 are proposed to be merged together, as discussed in Section 2d and 2e, to establish the new proposed rate options that have been designed to be revenue neutral. Further, the rates in the top portion of Table 7-2 map to the new Schedule AG-A, AG-B, or AG-C rate in the corresponding column below, for both rate design purposes, and for the mandatory migration or default reassignment of current legacy rate schedule customers to the new streamlined rate options.

TABLE 7-2
PROPOSED AGRICULTURAL RATE SIMPLIFICATION

Line No.	Item Description	New AG-A (< 35 hp)	New AG-B (> 35 hp)	New AG-C (> 35 hp)
1	**Transitional Legacy Rates**	AG-1A	AG-1B	
2	Modified Status Quo Rate Value Changes to Current Non-TOU and 4-Period and 5-Period Legacy TOU Rates	AG-RA AG-VA AG-4A AG-5A	AG-RB AG-VB AG-4B AG-4C	AG-5B AG-5C AG-ICE
3	Number of TOU Demand Charges	2	3, 5	3, 5
4	Number of TOU Energy Charges	4	4, 5	4, 5
5	**Restructured Consolidated New Rates**	**AG-A**	**AG-B**	**AG-C**
6	All Customers Must Transition to the New Rate Schedule Consolidation			
7	Number of TOU Demand Charges	2[a]	2	3
8	Number of TOU Energy Charges	4	4	4
9	Number of Customers	49,200	18,600	20,800
10	Average Annual kilowatt-hour (kWh) Per Customer	12,900	56,300	287,500
11	**Schedule AG-R** New optional rate with staggered off-peak days on 2 consecutive weekdays			

(a) PG&E proposes that all legacy and new AG-A customers with an interval meter be billed on the basis of metered kilowatt (kW) rather than the current "connected load" basis.

Notwithstanding the desire for simpler rates, PG&E proposes to retain the choice for larger customers between two rate options. The chart below in Table 7-3 demonstrates that for customers above 35 hp, Schedule AG-C will generally be better for higher load factor customers with more than 1,100 pumping hours per year, while Schedule AG-B will generally be better for lower load factor customers with less than 1,100 pumping hours per year. This 1,100 hour per year break-even point or demarcation between Schedules AG-B and AG-C generally aligns with the previous guidance of 1,500 hours for rate schedule selection between Schedules AG-4B and AG-5B. The slight reduction in the number of break-even hours may also help to slightly reduce the risk of selecting the larger schedule but not ending up exceeding the break-even number of pumping hours. However, if Schedules AG-1B, AG-4C, AG-5C, AG-RB and AG-VB had all continued to be available, this type of binary "Best Rate" selection guidance for customers above 35 hp would remain very complex when transposed among the current array of seven rate schedules applicable for service over 35 hp.

TABLE 7-3
AGRICULTURAL RATE SIMPLIFICATION "BEST RATE" SELECTION GUIDE FOR CUSTOMERS ABOVE 35 HORSE POWER

Line No.		Best Rate					
1	Annual Load Factor	5%	8%	10%	13%	30%	50%
2	Annual Pumping Hours	400	700	900	1,100	2,600	4,400
3	Pump Size (hp)						
4	35						
5	70						
6	100		**AG-B**			**AG-C**	
7	200						
8	300						
9	400						

The results shown in Table 7-3 are generalized assumptions based on a number of average usage level, TOU profile, and load factor assumptions that will not necessarily apply to individual customers. In addition, under the rate design rules between GRC's, which simply impose equal percentage changes, or now "equal cents" changes for the new proposed simplified rates, to distribution and generation rates to meet the revenue requirement change, the "Best Rate" relationship guidance in Table 7-3 should remain relatively stable. Thus, the more clear-cut binary best rate guidelines depicted in Table 7-3 under PG&E's proposed simplified rates should greatly reduce the difficulty agricultural customers face in determining or projecting their most favorable rate prior to the start of the growing season. PG&E's websites will continue to include a full array of rate analysis tools which customers may utilize to determine their preferred or best rate from among the streamlined options.

2. Rate Design Modifications

The proposed distribution, generation and total rate design for each agricultural rate schedule is based upon the principles established in Chapter 1, "Revenue Allocation and Rate Design Policy," of this exhibit. As discussed in Chapter 1, PG&E proposes to develop agricultural TOU rates that are revenue neutral with respect to agricultural non-TOU rates to avoid inappropriate rate relationships and free rider cost shifts.[6]

In summary, PG&E proposes the following primary changes to its agricultural rate design:

- Customer Charge: Increase customer charges for most agricultural customers to better reflect the cost of service.
- TOU Periods: Revise TOU periods for agricultural rate design consistent with the cost-based recommendation in Exhibit (PG&E-2), Chapter 12,[7] except that, here, PG&E proposes that agricultural customers' TOU rates continue to have no partial-peak period during the summer months. However, PG&E remains open to establishing a summer partial-peak period, as well as a spring super off-peak period, for agricultural customers.[8]
- Demand Charges: Modify the current use, in Schedules AG-RB, AG-VB, AG-4B and AG-5B, of three demand charges, and, in Schedules AG-4C and AG-5C, of five demand charges. Instead, PG&E proposes to impose only two demand charges on Schedules AG-A and AG-B, and three demand charges on Schedule AG-C.[9]

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6 The rate design discussion below does not apply to Schedule AG-ICE since its total rates are frozen throughout each calendar year and constrained to 1.5 percent schedule-average annual escalation on each January 1 through 2015 pursuant to D.05-06-016, or the 25 percent increases mandated for March 1, 2016, and January 1, 2017, through D.15-12-039, and Advice 4782-E, 4805-E and 4805-E-A. Schedule AG-ICE customers are mandated to transition to otherwise applicable agricultural rates in January 2018. As a result, Schedule AG-ICE total rates will not necessarily change on the 2017 GRC Phase II implementation date. Schedule AG-ICE is also subject to the default PDP requirements set forth in D.10-02-032, but Schedule AG-ICE customers may opt out of PDP and remain on Schedule AG-ICE. PG&E will seek appropriate annual January 1 rate changes on Schedule AG-ICE through separate advice letter filings, rather than in this proceeding. Schedule AG-ICE customers are shown in Appendix G as though currently served on AG-5B.

7 PG&E's proposed, updated TOU periods include a summer season from June through September and a winter season from October through May. The on-peak period is from 5 p.m. to 10 p.m. in all seasons and all days of the year. All other hours are off peak. PG&E has not proposed to institute a summer partial-peak period, or the super-off peak period for the agricultural class, as generally recommended in Exhibit (PG&E-9), Chapter 12. PG&E remains open to rates that include these features.

8 See Appendix E, Section G.

9 See Appendix E, Section D, Manageability.

- Simplify Rates: Establish rates that incrementally isolate primarily only one rate element of change among the options for which a customer is eligible. Thus, compared to AG-B, PG&E established AG-C rates that include a maximum demand charge like AG-B, but establish only a slightly higher customer charge, and a summer on-peak TOU demand charge in exchange for milder differentiation of summer TOU energy charges.[10]

PG&E's proposed agricultural rate design is discussed below in greater detail.

a. Customer Charges

Proposed agricultural customer charge targets are based on marginal customer costs scaled to 100 percent of the EPMC level. PG&E proposes to achieve partial movement toward these "target" levels. Current customer charges are $17.47 and $23.23 per month for most AG-A and AG-B customers, respectively. Larger customers currently pay customer charges of $36.36, $161.58 and $65.44 per month on Schedules AG-5B, AG-5C and AG-4C, respectively. PG&E proposes to increase agricultural customer charges by 20 percent in relation only to today's lower legacy customer charges, to $20.97 and $27.87 per month, respectively, for new AG-A and new AG-B customers, and to $43.63 for new AG-C customers, as shown in Table 7-4. These proposed increases move the agricultural customer charges gradually toward marginal cost and full EPMC target levels, to mitigate bill impacts. Residual customer charge revenues below EPMC levels will be collected through demand or energy charges.

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10 See Appendix E, Section D, Demand Charges and Energy Price Signals in Conflict.

TABLE 7-4
COMPARISON OF EXISTING, PROPOSED AND FULL EMPC TARGET AGRICULTURAL CUSTOMER CHARGES

Line No.	Legacy Schedule	Default Schedule	Current Customer Charge ($/mo)	Proposed Customer Charge ($/mo)	Marginal Cost ($/mo)	Full EMPC Target Customer Charge[(a)] ($/mo)
1	AG-1A, AG-4A, AG-RA, AG-VA, AG-5A	AG-A	$17.47	$20.97	$61	$113
2	AG-1B, AG-4B, AG-RB, AG-VB,	AG-B	$23.23	$27.87	$184	$341
3	AG-4C	AG-B	$65.44			
4	AG-5B	AG-C	$36.36	$43.63	$187	$348
5	AG-5C	AG-C	$161.58			

(a) As presented in Exhibit (PG&E-2), Chapter 7, "Marginal Customer Access Costs," marginal customer costs for AG-A and AG-B/C customers, respectively, are approximately $61 and $184 per month, prior to EPMC scaling, using the Real Economic Carrying Charge (or RECC method). A distribution EPMC scalar of approximately 1.86 would then apply, as is necessary to reconcile distribution marginal cost revenues to the higher distribution revenue requirement. Accordingly, the full EPMC target basic service fees would be approximately $113 and $341 per month. For the two largest current rates, Schedules AG-5B and AG-5C, the marginal cost level would be $187 per month, and the full EPMC level would be $348 per month.

These updated customer charges would take a very wide spread of current customer charges ($17-$161) and narrow the difference between them in the three new rate schedules ($20-$43). PG&E believes this will help make the process of rate schedule selection easier, as the primary comparative differences of significance would be driven mostly by demand and energy charges, not customer charges. These proposed levels represent a 20 percent increase above the customer charges currently paid by the vast majority of current agricultural customers, most of whom are not on the legacy AG-C options which have much higher fixed monthly customer charges. This will help mitigate any bill impacts arising from customer charge increases for the tens of thousands of customers moving from the legacy medium and large AG-B schedules to new Schedules AG-B and AG-C. As noted in Chapter 1 of this exhibit, PG&E will also revise all of these agricultural customer charges for changes in rates that are required to implement changes in distribution revenue.

b. Demand and Energy Charges

TOU demand charges on the legacy rates are differentiated by season, maximum demand, peak and partial-peak periods, where applicable. Currently, only the legacy AG-C options contain a partial-peak demand charge in the summer. Similarly, legacy TOU energy charges are differentiated as either 4-period or 5-period TOU rates, where applicable. PG&E proposes that these legacy rates remain with status quo designs using GRC Phase II rate design rules for revenue requirement changes between GRC Phase II cases.

PG&E proposes that demand and energy charges for the new Schedule AG-A, AG-B, AG-C and AG-R slate of simplified agricultural rates be set to collect distribution and generation revenues using the general rate design principles, seasonal and TOU rate relationships outlined in Chapter 1, "Revenue Allocation and Rate Design Policy," of this exhibit, as modified below.[11]

PG&E carefully considered its proposed rate design changes for the restructured rates to achieve some measure of simplification compared to current rates, yet at the same time make reasonable progress toward more cost-based rate designs. In some cases, PG&E specifically tailored or deviated from general rate design rules or methodologies to help mitigate bill impacts in deference to customer concerns voiced during the Collaborative process.

1) Distribution

To mitigate bill impacts and provide for reasonable transitions in rate designs used across customer classes, PG&E recommends assigning larger portions of the distribution revenue to demand charges for the largest customers, and assigning gradually smaller portions of remaining distribution revenue to demand charges for

[11] PG&E is not proposing to adjust distribution and generation demand and energy charges for the legacy agricultural rates schedules.

smaller customers—with any residual revenues collected through energy charges. This principle was used to assign increasing amounts of distribution revenue after customer charges to distribution demand charges for the new Schedule AG-A, AG-B, and AG-C rates, with 50 percent of total allocated non-customer distribution revenues assigned to demand charges for the small rate, 60 percent to demand for the medium simple rate, and 80 percent to demand for the medium complex rate, with all residual revenues assigned to distribution energy charges.

The three basic new Schedules AG-A, AG-B, and AG-C have no TOU differentiation at all in the distribution components, with equal distribution maximum “anytime” demand charges by season, and mildly seasonally differentiated flat non-TOU distribution energy charges. In order to provide proper TOU differentiation of distribution charges, a partial-peak period would be more appropriate to capture the wider range of local distribution peaks. However, input during the Collaborative process suggested that, as part of simplifying agricultural rates, a partial-peak period was not desirable.[12] For this reason, PG&E’s proposed agricultural TOU rates have neither a partial-peak period in the summer, or TOU differentiation of distribution rates. PG&E also proposes to retain seasonal and TOU distribution demand and energy component rate changes on an equal cents per kWh basis for future distribution revenue requirement changes after a decision in this proceeding.

The distribution demand charges are collected solely through “connected load” charges on legacy AG-A rates and new

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[12] See Appendix E, Section G.

Schedule AG-A.[13] For legacy AG-A and new AG-A customers with an interval meter, PG&E proposes that customers be charged on the basis of measured kW demands. Customers without interval data would continue to be billed on a connected load basis until equipped with an interval capable meter.

2) Generation

For generation rate design, PG&E proposes to set generation rates by season in proportion to the marginal generation cost revenue. PG&E proposes that total generation revenues be allocated 20 percent to capacity and 80 percent to energy on all proposed rate schedules. However, to better conform to the input from the Collaborative process, AG-A and AG-B have no generation demand charges. AG-C provides an option for larger customers with a summer generation peak demand charge. Generation capacity costs were converted to TOU-based summer generation energy charges on the new AG-A and AG-B options in a 4-to-1 ratio for on-peak summer versus off-peak summer TOU energy rates. In addition, because the generation EPMC scalar has a value of 2.21, PG&E has used raw marginal energy cost generation TOU rate differences, rather than EPMC scaled generation rates, to prevent rate differentials from implying bill savings due to load shifting that far exceed actual cost savings.

For similar reasons, PG&E proposes that all interim rate changes between GRC's switch from "equal percent" revisions to rates, to instead use "equal cents" revisions to rates. This "equal cents" method will apply to both new rates and legacy rates. The

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13 "Connected load" charges are based on motor or pump equipment capacity nameplate ratings that do not change from month to month, regardless of actual kW demands in each month. Generally, as a historical matter, demand meters were more expensive than warranted for smaller agricultural customers under 35 hp. However, because the agricultural class on average has the most volatile electric loads of any customer class, connected load charges were imposed even on smaller agricultural customers to better recover fixed infrastructure costs. Similarly, as a historical matter, until eliminated in 2006, "ratcheted demand charges" were applied to medium and large agricultural customers based on the maximum metered kW demand in the prior 11 months and the current month, or the trailing 5 months of the same season.

"equal cents" approach will apply to both energy charges and demand charges on the rates for new Schedules AG-A, AG-B, AG-C and AG-R, as well as on all legacy rate schedules.

The resulting seasonal or TOU distribution and generation capacity demand or energy charges will send appropriate marginal cost based price signals that reflect the seasonal distribution and generation capacity costs of serving customer kW demands. All distribution and generation voltage discounts are expressed in terms of reductions to seasonal maximum demands.

c. Options for Agricultural Customers With Longer Off-Peak Period Operations

Currently, PG&E offers two electric rate schedules that include opportunities for extended operations during off-peak periods. Schedule AG-R is a split week optional TOU rate schedule that provides customers the option to designate either Monday through Wednesday, or Wednesday through Friday, as their days subject to on-peak pricing. Schedule AG-V is a short peak optional TOU rate schedule that allows customers to choose a four-hour rather than six-hour peak period, which may start at one of three times: noon, 1 p.m. or 2 p.m.

Pursuant to D.11-12-053, TOU Schedules AG-R and AG-V were to be eliminated, effective March 1, 2014, for customers with 12 months of interval billing data. However, due to the four-year drought from 2012 through 2015, the elimination of Schedules AG-R and AG-V was suspended in March 2014, and again in March 2015, by joint request of PG&E, CFBF, and AECA to the CPUC's Executive Director, and was ultimately entirely rescinded in D.15-08-005. Rescinding the elimination of Schedules AG-R and AG-V was necessary to mitigate water table and pumping quality issues attenuated by water scarcity conditions. Eliminating AG-R and AG-V would have forced growers to pump more simultaneously, in a manner that would have aggravated the above drought considerations.

During the Collaborative process, parties sought to carry forward the type of pumping flexibility and long off-peak pumping hour periods available on Schedules AG-R and AG-V. The new Schedule AG-R consolidates and expands the prior options available under the legacy versions of Schedules AG-R and AG-V. The new Schedule AG-R includes two consecutive off-peak weekdays. Schedule AG-R may involve a slightly higher design cost basis to offset the fact that on-peak costs are spread over fewer hours. Collaborative parties felt that the availability of two consecutive off-peak days eliminated the need for the staggering of on-peak hours (i.e., similar to the current Schedule AG-V). However, AG-R rate design was not complete in time for filing. Therefore, AG-R is not included in Appendices B or G.

Table 7-5 illustrates the new options PG&E is considering proposing for the new Schedule AG-R.

TABLE 7-5
NEW PROPOSED SCHEDULE AG-R GROUPS

Line No.	Code	Off-Peak Days
1	MT	Monday and Tuesday all year
2	WT	Wednesday and Thursday all year

PG&E will work with customers in a local circuit area to place customers in different groups to stagger loads to avoid creating local system constraints, and to mitigate overlapping pumping operations that could otherwise aggravate local ground water pumping and pumping efficiency or equipment concerns. PG&E will have the final authority to designate customers in each group to accommodate these objectives, but will seek to accommodate customer operational efficiency goals and convenience to the greatest extent possible.[14]

d. TOU Revenue Neutrality and Intraclass Revenue Allocation

To avoid inappropriate rate relationships and free rider cost shifts that may automatically happen when customers migrate from non-TOU to TOU rates, or among alternate rate options a given customer may be

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14 PG&E will generally default existing Schedule AG-R and AG-V customers to new Schedule AG-A if under 35 hp, and new Schedule AG-B if over 35 hp. However, customers may instead opt-in to the new successor Schedule AG-R if they wish, or to new Schedule AG-C if over 35 hp.

eligible for, PG&E proposes to establish all agricultural TOU rate options on a revenue neutral basis for the restructured rate options. The revenue neutral rate design process generally requires all corresponding TOU and non-TOU billing determinants to be merged together to first design the mandatory TOU rate. The rates for any related TOU or non-TOU corresponding rate subgroups are then designed based on only the billing determinants of that corresponding rate subgroup, combined with a revenue allocation equal to the revenue that each rate subgroup would pay on the mandatory TOU rate. This process may require the use of class load research data and available interval data to develop: (1) TOU billing determinants for non-TOU customers; and (2) proposed 4-period TOU billing determinants that estimate TOU usage for all customers under the new proposed seasons and later TOU hours.

More specifically, for purposes of establishing revenue neutral rate design relationships, PG&E proposes to merge the rate design and billing determinants across appropriate sets or groups of legacy and restructured rate schedules. PG&E proposes to merge all AG-1A, RA, VA, 4A and 5A customers together for the purpose of designing the new AG-A TOU rate. Similarly, PG&E proposes to merge all AG-1B, RB, VB, 4B, 4C, 5B, and 5C customers together for the purpose of designing the new AG-B and AG-C rate schedules. PG&E first designed the AG-A and AG-C rates, based respectively on all AG-A and all AG-B/C customers. PG&E then calculated the revenue paid on AG-C by AG-5B and AG-5C customers, then used all remaining or residual revenue allocated to the agricultural class to design the new AG-B rates.

This approach will generally establish TOU rate options that only produce bill savings if the participant’s usage achieves a lower on-peak share than average for the schedule or class. This also ensures that TOU customers as a whole pay the same amount on TOU rates as on non-TOU rates, or pay the same amount if they have an option of more than one TOU rate. In addition, since the transition to mandatory TOU is expected to be nearly complete in 2017, this will avoid the revenue shortfalls that in the past may have been associated with self-selection bias, and should generally assure that the agricultural class revenue requirement is fully collected from agricultural customers.[15]

e. Intraclass Revenue Allocation

The above Section 2a, b, and d rate design modifications each occur within the context of the agricultural class 0.0 percent capped allocation presented in Chapter 2 of this exhibit. Consequently, PG&E notes that each of the respective Legacy or new schedule-average rates are the result of intraclass revenue allocation adjustments developed as a rate design matter, rather than as part of the global revenue allocation process. That is, as part of the global revenue allocation process, the agricultural class was capped at a 0.0 percent increase. While this global revenue allocation process assigned zero percentage changes to each individual Legacy agricultural rate schedule, the newly proposed merged rate schedules of the three new AG-A, B and C revenue neutral rate design groups did not result in each receiving zero percent changes. Instead, after performing the revenue neutral rate design consolidation operations described above, varying changes resulted for each individual new agricultural rate schedule as shown in PG&E's proposed revenue allocation in Appendix A, "Revenue and Average Rate Summary at Proposed Rates" due either to rounding, PPP impacts, or the merger or combination of Legacy rates into new rates.

Again, generally, the imposition of TOU revenue neutrality will as a rule combine all TOU and non-TOU customers together for rate design purposes. This in turn will result in a decrease to non-TOU rates, and an increase to TOU rates. While as a group the new AG-A customers receive a 0.13 percent increase, the new AG-B customers receive a 0.15 percent increase, and the new AG-C customers receive a 0.58 percent increase.

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15 After the fact revenue adjustments required by D.11-12-053 and D.15-08-005 are not expected to be needed after January 1, 2018.

3. Other Issues

a. Demand Charge Limiter (DCL)

PG&E proposes that the basic ongoing demand structure for the proposed new agricultural rates be subject to a new demand charge limiter. The proposed demand charge limiter will govern the combined impact of demand and energy charges, exclusive of customer charges, so that customers do not pay an inordinately high average rate per kWh during any individual billing period. This high average rate phenomenon is often related to the case where load is imposed in only one or two of the 30 days of the billing period, or may relate to energy efficiency pump tests, or the testing of frost protection wind machines.

The proposed demand charge limiter per kWh could in theory apply to each of the four main proposed new agricultural rate options, Schedules AG-A, AG-B, AG-C and AG-R, and implies a progressively lower number of operating hours or lower load factor assumption for progressively larger customers. For example, simply to illustrate, a proposed $1.00 per kWh DCL would protect new Schedule AG-C customers once they go below approximately 12 operating hours each in the on-peak and off-peak summer period, but would only protect new Schedule AG-A and AG-B customers once they fall below 3 or 4 operating hours each in the on-peak and off-peak summer period. PG&E would then estimate demand charge limiter related revenue shortfalls, assigned to distribution, and allocate such shortfalls back to the schedule of origin.

PG&E also understands that some agricultural customer have reported that motors driven by variable frequency drives contain cooling fans which operate automatically and cannot be controlled during Peak Day Pricing (PDP) Event Hours even if the customer decreases all other usage to zero. PG&E is considering how to address this issue, but clarifies that the proposed new demand charge limiter is to be applied before all PDP credits and charges have been assessed.

b. Optimal Billing Period Program

PG&E proposes to retain the Optimal Billing Period (OBP) Program that was reinstituted in 2009 in D.09-02-019 on Schedule AG-5C through Advice Letter 3439-E for eligible customers. PG&E proposes no changes to the current OBP Program. Although PG&E's consideration of a possible proposed new Demand Charge Limiter will provide some measure of relief similar to Optimal Billing, the re-designation of meter read dates facilitated by Optimal Billing provides a greater level of protection from crop processing production timing that fails to align with meter read dates. However, given the proposed elimination of legacy Schedule AG-5C, PG&E proposes to offer Optimal Billing only on new Schedule AG-C.

D. Conclusion

In this chapter, PG&E has detailed its proposals for rate design for the agricultural customers in this Phase II proceeding. PG&E requests that the Commission approve the agricultural rate design revisions proposed in this chapter. Compared to the complex and confusing status quo array of agricultural rate schedules, PG&E believes its rate restructuring proposal to be simpler and easier to understand. PG&E's proposals will achieve a more uniform, simplified, and straightforward customer understanding of how to manage their accounts to minimize their bills. PG&E's proposals will better respond to agricultural concerns over demand charges and the difficulty of projecting the electricity needed to support agricultural operations subject to unique uncertainties. Further, while balanced with other objectives, PG&E's agricultural rate design proposals will achieve movement toward cost of service targets by realigning demand versus energy, seasonal, and TOU ratios to reflect underlying distribution and generation marginal costs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

STREETLIGHTING RATE DESIGN

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STREETLIGHTING RATE DESIGN

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CHAPTER 8
STREETLIGHTING RATE DESIGN

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E or the Company) 2017 General Rate Case (GRC) Phase II rate design proposals for the streetlight customer class. As described in Chapter 1, "Revenue Allocation and Rate Design Policy" of this exhibit, a key objective of PG&E's proposals for rates is to adjust rates to better reflect distribution and generation costs, balanced with other objectives such as rate stability.

PG&E's rate design proposals for the Streetlight Class are described in the following testimony and include:

- Adjust facility charge rates to reflect a reallocation of costs resulting from a change in the most common lamp type.
- Continue the Network Controlled Dimmable Streetlight Pilot Program.
- Increase the Schedule LS-3 customer charge to better reflect cost of service.

This chapter focuses on PG&E's rates for distribution and generation services, including adjustments to streetlight facility charges.[1]

The remainder of this chapter is organized as follows:

- Section B – Background
- Section C – Non-Energy Facility Charge Calculation for Schedules LS-1, LS-2 and OL-1
- Section D – Energy Charge and Total Streetlight Rates for Schedules LS-1, LS-2 and OL-1
- Section E – Rate Design for Schedule LS-3
- Section F – City and County of San Francisco Streetlight Rates
- Section G – LS-1 Light-Emitting Diode Streetlight Conversion Program
- Section H – Network Controlled Dimmable Streetlight Pilot Program
- Section I – Conclusion

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1 Public Purpose Program rates for streetlighting customers are designed in accordance with the guidelines described in Chapter 1 of this exhibit.

B. Background

In this chapter, PG&E addresses rate design for Schedules LS-1, LS-2, LS-3, OL-1 and City and County of San Francisco (CCSF) streetlights. Schedules LS-1and LS-2 provide options for illuminating public streets, highways, and other outdoor ways and places and are designed as a fixed monthly charge. Schedule OL-1 is also designed as a fixed charge per month for private, customer-owned outdoor lighting. PG&E also develops fixed monthly charges for CCSF's streetlights. Schedule LS-3, however, is a metered schedule with a customer charge and an energy rate that does not vary by time of day or season. PG&E proposes to continue this same basic structure for LS-3.

Schedules LS-1, LS-2, OL-1 and CCSF streetlights include a fixed monthly charge per lamp based on the most common type and size of lamp within each rate schedule and the type of service provided by PG&E (e.g., LS-1A, LS-1C, etc.). The monthly charge consists of a non-energy facility portion and an energy portion based on the estimated usage per lamp and an average energy rate. In PG&E's 2014 GRC Phase I proceeding, PG&E established an incremental non-energy facility charge which was applied to LS-1 customers who elected to participate in the voluntary Light-Emitting Diode (LED) conversion program. In this proceeding, PG&E proposes to eliminate this adder for PG&E and CCSF *non-decorative* streetlights, replacing it with an LS-1 facility charge for LED lamps.

In keeping with PG&E's proposal not to adjust distribution or generation revenue in this proceeding, as described in Chapter 1 of this exhibit, PG&E proposes to retain the current facility charge, distribution, and generation revenue currently embedded in streetlighting rates.

C. Non-Energy Facility Charge Calculation for Schedules LS-1, LS-2, OL-1 and CCSF Streetlights

This section describes the non-energy facility charge rate design for Schedules LS-1, LS-2, OL-1 and CCSF streetlights.

In this proceeding, PG&E continues to base its non-energy facility charge proposal on a simplified non-energy streetlight rate design model. This type of simplified model was first introduced in PG&E's 2003 GRC Phase II (Decision (D.) 05-11-005) and has continued to be used in PG&E's GRC

Phase II proceedings since that time. The method proposed herein was most recently adopted in the settlement approved by the CPUC in D.15-08-005 (PG&E's 2014 GRC Phase II decision), and is the basis for the currently effective non-energy facility charge for these rate schedules.

While there are multiple lamp types with different voltages and wattage within each streetlight rate schedule, the simplified non-energy streetlight model calculates a single rate for each schedule using the most common lamp type (e.g., High Pressure Sodium Vapor (HPSV)), voltage, and wattage found in each rate schedule in the 2014 and earlier GRC proceedings. This simplified approach significantly reduced the number of non-energy facility charges to the current level of fewer than 25 rates. In comparison, the previous, more complex streetlight model had a separate rate for each of the over 130 lamp types. In this proceeding, PG&E proposes to revise non-energy facility charges to reflect the most common lamp type expected by the end of 2017. For most rate schedules, the most common lamp type is expected to be an LED lamp. The total proposed illustrative non-energy facility charges for Schedules LS-1, LS-2, OL-1 and CCSF streetlights are shown in Table -2, at the end of this chapter.

The three components of the non-energy facility charge, using the simplified model, are:

- Universal Charge;
- Remaining operations and maintenance (O&M) Expense Charge; and
- Plant-Related Charge.

Table 8-1, below, provides a summary of the applicability of these non-energy facility charge components to each streetlight rate schedule:

TABLE 8-1
APPLICABILITY OF NON-ENERGY FACILITY CHARGE COMPONENTS

Line No.	Streetlight Rate Schedule	Universal Charge	O&M Charge	Plant-related Charge
1	LS-1A through LS-1F	Yes	Yes	Yes
2	LS-2A	Yes	No	No
3	LS-2C	Yes	Yes	No
4	OL-1	Yes	Yes	Yes
5	All City and County of San Francisco Lamp Schedules	Yes	Yes	Yes

1. Universal Charge

The Universal Charge is imposed on all LS-1, LS-2, OL-1 and CCSF streetlight customers regardless of whether the streetlight is owned by the customer or by PG&E. The Universal Charge covers recovery of O&M, Customer Accounts, and Administrative and General (A&G) expenses.

The O&M portion of the Universal Charge includes Distribution Maps and Records, as well as Supervising and Engineering costs. The Customer Accounts portion of the Universal Charge includes the Streetlight Inventory Program. The A&G portion of the Universal Charge is calculated by multiplying the test year electric distribution A&G loader by the O&M expense.

a. O&M Expense

For its 2017 streetlight rates, PG&E uses 2017 test year estimates for the streetlight O&M account shown in the Federal Energy Regulatory Commission (FERC) Account 596 (Distribution Maintenance of Streetlights and Signal Systems).

As it did in the prior GRC Phase II proceedings beginning 2007, PG&E has continued to separate the O&M streetlight expenses into the Universal Charge (distribution maps and records, and supervision and engineering) and the Remaining O&M Expense Charge (group replacements and burnouts). This separation enables PG&E to unbundle the expense for group lamp replacements and burnouts.

b. Customer Accounts Expense

Similar to the 2014 GRC Phase II, in this 2017 GRC Phase II, PG&E proposes to include the Streetlight Inventory Program cost in the Universal Charge. This cost is specifically related to the lamp inventory for Schedules LS-1, LS-2 and OL-1, and is driven by recordkeeping for each streetlight in the streetlight inventory.

c. A&G Expenses

For this 2017 GRC Phase II, PG&E proposes to continue to calculate the A&G expenses by multiplying the test year electric distribution A&G loader by the O&M expenses in the Universal Charge.[2] The electric distribution A&G loader for this 2017 GRC Phase II, is equal to 26.17 percent, as described in Exhibit (PG&E-2), Chapter 13, Marginal Cost Loaders and Financial Factors.

2. Remaining O&M Expense Charge

O&M expenses that were not incorporated into the Universal Charge, such as group replacement and burnouts, appear in the Remaining O&M Expense Charge. For this 2017 GRC Phase II, PG&E proposes to continue to calculate the A&G expenses for this component by applying the test year electric distribution A&G loader discussed in the previous paragraph.

3. Plant-Related Charge

The Plant-Related charge is developed first by determining the revenue requirement for the capital cost of the streetlights and then separately determining the replacement cost for each type of lamp in order to allocate the revenue requirement among all lamp types in Schedules LS-1, OL-1, and CCSF streetlights.

a. Plant Revenue Requirements

The Plant-Related charge is based on a revenue requirement that is derived using the year balances of the streetlight plant accounts. The revenue requirement is based on the cost of owning the streetlight facilities for Schedules LS-1, OL-1, and CCSF and includes costs for depreciation, uncollectibles, franchise fees, income taxes, property taxes and return. PG&E's calculation of the streetlight revenue based on its proposals in GRC Phase I would imply a significant increase to non-energy facility charge rates. As noted above, however, PG&E is not requesting an increase to recover the full revenue requirement from the streetlighting customers at this time. Instead, PG&E is proposing to continue the current level of streetlight facility charge revenue, and to reallocate that revenue slightly to reflect a change to the 'most common lamp type' as discussed in more detail below.

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2 A&G Loader is already embedded within the customer account expenses portion of the Universal Charge.

b. Replacement Costs

The revenue requirement is allocated to each streetlight rate schedule according to the replacement cost of each lamp type.

There are four basic lamp types currently in use on PG&E's system: (1) HPSV; (2) Mercury Vapor (MV); (3) incandescent; and (4) newer technologies like LED or induction[3] street lamps (currently still in relatively limited use due to the high capital investment costs). HPSV lamps have historically been the most common lamp type owned by PG&E. For most rate schedules, PG&E expects that, by 2017, the most common lamp type will be an LED lamp, and, accordingly, proposes to change rates to make LED the most common lamp type in this proceeding as described further below.

For this 2017 GRC Phase II, for most lamp types, PG&E continues to use 2012 streetlight replacement cost data, the most up-to-date data available, escalated to 2017 dollars. The LED lamp, fixture and photo control costs are expressed in 2015 dollars and do not include escalation. PG&E continues to use the same materials and labor categories included in the streetlight settlement approved in 2014 GRC Phase II Decision.[4] MV and incandescent lamps are old, obsolete technologies that are not supported by manufacturers and/or for which spare parts/supplies are no longer available. Therefore, as MV lamps fail or burn out, the MV luminaire (and not just the lamp itself) is replaced by HPSV luminaire with the equivalent number of lumens. As a result, PG&E derived the replacement cost for these obsolete MV lamps based on the replacement cost for HPSV lamps with the equivalent number of lumens.[5]

In the case of incandescent lamps that operate in a serial circuit, the fixtures, circuitry, and transformers need to be replaced with a new

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3 PG&E does not have any Company-owned induction lamps under LS-1.

4 PG&E obtained the cost data for materials and labor (e.g., for each lamp type) to install the replacement lamp from standard estimating tools that are routinely used in most construction projects.

5 MV and incandescent lamps make up only 21,000 of the approximately 197,000 PG&E-owned streetlights encompassed by the Plant-Related Charge.

HPSV lighting system, as these incandescent components are no longer available. The replacement costs for these incandescent lamps are based on the average per-lamp cost from an incandescent lamp conversion project that was completed in 2009 for 19 lamps in San Francisco. That project's average per-lamp conversion cost was used as a proxy for incandescent lamp replacement costs. Since the fixtures within the conversion project only accounted for a small portion of total conversion costs, there is no cost differentiation to account for various lamp sizes.

c. Plant Revenue Requirement Allocation

Once the total replacement costs are determined, the Plant Revenue Requirement, or in this case the total current plant-related facility charge revenue, is allocated to each lamp type in a three-step process. First, PG&E calculates the Revenue Allocation Factors (RAF), which is the ratio of the embedded revenue requirements compared to the total replacement costs for all lamps under Schedules LS-1, OL-1 and CCSF. Second, PG&E multiplies the RAF by the replacement cost on each of the most common lamp type in Schedules LS-1, OL-1 and CCSF to yield an annualized plant related charge rate. Lastly, the annualized charge rates are then scaled to equal to the total required revenue.

D. Energy Charge and Total Streetlight Rates for Schedules LS-1, LS-2 and OL-1

The total monthly charge per lamp for Schedules LS-1, LS-2 and OL-1 is the sum of the non-energy facility charge and the product of the energy usage per lamp and a volumetric (per kWh) rate which includes all other costs allocated to these customers.

Since Schedules LS-1, LS-2 and OL-1 are not metered, energy usage for these rate schedules is derived based on the type and size of lamp and lamp ballast, and the estimated number of hours during which the lamp would operate each month. For this GRC Phase II, PG&E proposes no change in the estimated hours of operation. Lamps are assumed to be operated for approximately 11 hours per night on average, but not to exceed 4,100 hours per year for all-night rates.

The volumetric energy rate is determined by subtracting non-energy facility charge revenues from Schedules LS-1, LS-2, OL-1, and CCSF lamps as well as the applicable Schedule LS-3 basic service fee from the total revenue allocated to the streetlight class, and then dividing the difference by the applicable sales, in kilowatt-hours (kWh).

E. Rate Design for Schedule LS-3

As noted in the Background section of this testimony, Schedule LS-3 includes a customer charge and an energy rate that does not vary by season or by time of use. PG&E proposes to increase the customer charge from $6 per month to $7.50 per month (expressed on a daily equivalent basis) to better reflect the cost of service.[6] The energy rate is set equal to the volumetric rate established for Schedules LS-1, LS-2 and OL-1.

F. City and County of San Francisco Streetlight Rates

PG&E provides O&M services to the streetlights that are located in San Francisco. These CCSF streetlights obtain their energy from the city's Hetch Hetchy Project and not from PG&E. In this proceeding, with the exception of the rates for CCSF Rate Schedule 9, PG&E proposes to set rates for CCSF's streetlights using the same approach adopted in the settlement approved by the CPUC in D.15-08-005 (PG&E's 2014 GRC Phase II Decision).[7]

Since PG&E is not changing the overall revenue collected from all streetlight facility rates, with the exception discussed above, the change to CCSF streetlight rates results from a reallocation of revenue due to the change in the most common lamp type. PG&E's proposed non-energy facility charges for the CCSF rate schedules are shown in Table 8-2 at the end of this chapter.

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6 The customer charge for Schedule LS-3 was last revised by the CPUC in D.07-09-004 (PG&E's 2007 GRC Phase II proceeding). The marginal customer access cost for streetlights is approximately $56 per month, or about $104 per month, if scaled to full cost using an equal percentage of marginal cost scalar of 1.86.

7 PG&E is not seeking an adjustment to the rate for CCSF Rate Schedule 9 Duplex (1) due to the uncertainty associated with the replacement costs for these lamps, which could be much higher than the value currently used.

G. LS-1 Light-Emitting Diode Streetlight Conversion Program

As noted above, the LED streetlight Conversion Program for *non-decorative* streetlights will be eliminated and replaced with an LED streetlight facility charge rate. This revision will eliminate the need for the incremental non-energy facility charge adder which was applied to LS-1 customers who elected to participate in the voluntary Light-Emitting Diode (LED) conversion program for *non-decorative* streetlights. That is, rather than calculating an LED conversion adder, PG&E would calculate the facilities cost for LS-1 using an LED replacement cost.[8] PG&E would continue to charge the LED Program Incremental Facility Charge established in Advice 4661-E (for PG&E owned *decorative* streetlights) and Advice 4662-E (for CCSF *decorative* streetlights) at its current rate for customers who elect to participate in the LED Streetlight Conversion Program.

H. Network-Controlled Dimmable Streetlight Pilot Program

A Pilot Program for Network-Controlled Dimmable Streetlights (Pilot) was established as part of the Streetlight Settlement Agreement approved by the CPUC in PG&E's 2011 GRC Phase II (D.11-12-053).[9] The Pilot was revised in the Streetlight Settlement Agreement approved by the CPUC in PG&E's 2014 GRC Phase II (D.15-08-005).[10] As compared with the 2011 Dimmable Pilot Program, the 2014 Dimmable Pilot Program was expected to provide dimmable streetlight service as an option to Schedule LS-2 that was simpler and offered participants some certainty that they would benefit from related energy savings in a timely and mutually workable way. Among other benefits, the agreed revisions for the 2014 Dimmable Pilot Program were developed to: (1) allow greater certainty of rate savings as an input to local governments' decisions as to whether to install a dimmable streetlight control system; (2) make the rate more economically feasible for smaller jurisdictions, in that the 2014 Dimmable

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8 Pursuant to the Streetlight Settlement approved by D.15-08-005, the need to continue the incremental facility charge would be determined in the 2017 GRC Phase II. (*See* the Streetlight Rate Design Settlement adopted in D.15-08-005, mimeo, p. 6-7.)

9 *See* D.11-12-053, mimeo, pp. 55-58, adopting, without modification, the uncontested Amended Streetlight Settlement Agreement attached to that decision as Appendix D, Attachment 3. *See also* Resolution E-4421 approving the necessary Special Contract that would allowing participants' billing to deviate from PG&E's existing LS-2 streetlight rate schedule, to allow for reductions due to dimmable LED streetlights under this Pilot.

10 *See* the Streetlight Rate Design Settlement, p. 5.

Pilot was scalable; and (3) reduce the administrative cost and burden for local governments and for PG&E.

Pursuant to D.15-08-005, the 2014 Dimmable Pilot Program was to end on the later of December 31, 2017 or a decision in the 2017 GRC Phase II proceeding, unless it is specifically authorized to continue by that decision. The Streetlight Rate Design Settlement, adopted by the CPUC in D.15-08-005, required PG&E to assess the results of the 2014 Pilot Program in its 2017 GRC Phase II proceeding and make a recommendation in this proceeding for the Pilot Program going forward. Specifically, PG&E's recommendation could continue, revise or remove the pilot status, or discontinue the pilot entirely. PG&E's evaluation was to be based in part on the success of the Pilot in properly capturing each customer's usage, as well as an assessment with regard to whether the Pilot as designed is sustainable going forward. (*See* Settlement, p. 12.) The 2014 Pilot Settlement, which the CPUC approved in August 2015, became effective on January 1, 2016. However, since this new program has been available only a very short time, no experience has yet been gained which would allow PG&E to evaluate its success. Accordingly, in this proceeding, PG&E simply proposes to continue offering this dimmable Pilot Program through its next Phase II case. In that proceeding, PG&E will report on its experience with the pilot program, and make a recommendation with regard to the future of the program based on the same standards established by the Streetlight Rate Design Settlement, described above.

I. Conclusion

PG&E requests that the Commission adopt its proposed rate design for non-energy facility charges for Schedule LS-1, LS-2, OL-1, and CCSF streetlights, its proposed customer charge for Schedule LS-3, and for energy charges for all streetlight rate schedules. PG&E also requests elimination of the LED conversion adder for *non-decorative* streetlights and continuance of the 2014 Dimmable Pilot Program.

TABLE 8-2
FACILITY CHARGES FOR STREETLIGHT RATES

	Rate Schedule	Service	Lamp Counts: Plant Charge	Lamp Counts: Universal Charge	Lamp Counts: O&M Charge	Monthly Rate: Plant Charge	Monthly Rate: Universal Charge	Monthly Rate: O&M Charge	Total Monthly Facility Charge	Annual Revenues - Proposed ($000): Per Schedule	Annual Revenues - Proposed ($000): Per Class
1	LS-1A	PG&E owns and maintains luminaire, control facilities, support arm, and service wiring on its existing distribution pole, and all lights. Most common lamp type: LED 29W.	58,691	58,691	58,691	$2.855	$0.207	$3.788	$6.849	$ 4,824	
2	LS-1B	PG&E owns and maintains luminaire, control facilities, support arm, pole or post, foundation and service connection and where customer has paid the estimated installed cost of the luminaire, support arm and control facilities. Most common lamp type: MV 175W (HPSV 70W equivalent).	42	42	42	$3.131	$0.207	$3.788	$7.126	$ 4	
3	LS-1C	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring as required. (Ownership of pole or post, support arm and foundation by customer where light is the only light on a pole or where this schedule is applied to all lights on the customer owned pole. Also applies to second and all multiple lights on poles or posts owned by PG&E. Most common lamp type: LED 29W.	20,655	20,655	20,655	$2.686	$0.207	$3.788	$6.680	$ 1,656	
4	LS-1D	PG&E owns and maintains its standard post top luminaire, control facility, internal post wiring, standard galvanized steel post (20-foot mounting height or less) and foundation where customer pays for the estimated and installed cost of the post, support arm (if any) and foundation. Most common lamp type: HPSV 70W.	19,223	19,223	19,223	$5.336	$0.207	$3.788	$9.331	$ 2,152	
5	LS-1E	PG&E owns and maintains its standard luminaire, control facility, internal pole wiring, service connection, galvanized steel pole and foundation where the customer has paid to PG&E the estimated installed cost of the pole, support arm and foundation. Most common lamp type: LED 29W.	39,166	39,166	39,166	$5.670	$0.207	$3.788	$9.664	$ 4,542	
6	LS-1F	PG&E owns and maintains a standard luminaire, control facility, support arm, and service connection on its standard pole or post, installed solely for the luminaire. Most common lamp type: LED 29W.	18,617	18,617	18,617	$3.833	$0.207	$3.788	$7.828	$ 1,749	$14,926
7	LS-2A	City Owned and Maintained		591,506			$0.207		$0.207	$ 1,466	
9	LS-2C	City Owned and PG&E Maintained		8,120	8,120		$0.207	$3.788	$3.994	$ 389	$1,855
10	OL-1	Outdoor area lighting service where street lighting schedules are not applicable and where PG&E installs, owns, operates and maintains the complete lighting installation on PG&E's existing wood distribution poles or on customer-owned poles acceptable to PG&E installed by the customer on his private property.	20,851	20,851	20,851	$3.131	$0.207	$3.788	$7.126	$ 1,783	$1,783
	CCSF Standard:										
11		CCSF Rate Schedule No. 1 (LS-1A HPSV 100W)	16,234	16,234	16,234	$3.108	$0.207	$3.788	$7.103	$ 1,384	
12		CCSF Rate Schedule No. 3 (LS-1A HPSV 150W)	198	198	198	$3.098	$0.207	$3.788	$7.093	$ 17	
13		CCSF Rate Schedule No. 4E (LS-1E HPSV 100W)	1,089	1,089	1,089	$5.727	$0.207	$3.788	$9.721	$ 127	
14		CCSF Rate Schedule No. 4A (LS-1E Mercury Vapor 175W)	8	8	8	$5.946	$0.207	$3.788	$9.941	$ 1	
15		CCSF Rate Schedule No. 6 (LS-2B)		24	24		$0.207	$3.788	$3.994	$ 1	
16		CCSF Rate Schedule No. 7									
	CCSF Non-Standard										
		CCSF Rate Schedule No. 4A:									
17		Incandescent 295W	298	298	298	$15.718	$0.207	$3.788	$19.712	$ 70	
18		Mercury Vapor 400W	2	2	2	$7.763	$0.207	$3.788	$11.757	$ 0	
		CCSF Rate Schedule No. 5:									
19		HPSV 100W	55	55	55	$7.778	$0.207	$3.788	$11.773	$ 8	
20		Incandescent 405W	132	132	132	$15.718	$0.207	$3.788	$19.712	$ 31	
		CCSF Rate Schedule No. 6A (Chinatown Area) - HSPV 250W	59	59	59	$52.885	$0.207	$3.788	$56.880	$ 40	
		CCSF Rate Schedule No. 9 (Triangle District)									
		HPSV:									
21		150W 16,000 LUMENS DUPLEX (1)	193	193	193	$58.057	$0.207	$3.788	$62.052	$ 144	
22		150W 16,000 LUMENS DUPLEX (2)	193	193	193	$1.196	$0.207	$3.788	$5.191	$ 12	
23	CCSF Subtotal		18,461	18,485	18,485	$4.286	$0.207	$3.788	$8.280	$ 1,835	$1,835
24	Lamp Count Totals		195,706	795,357	203,850						
25	Annual Revenues ($000)		$9,163	$1,971	$9,266					$ 20,400	$20,400

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

STANDBY RATE DESIGN

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STANDBY RATE DESIGN

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) proposes standby rates to be implemented pursuant to a decision in Phase II of its 2017 General Rate Case (GRC). As described in Chapter 1, "Revenue Allocation and Rate Design Policy" of this exhibit, these proposals include changes to distribution, public purpose program (PPP) and generation rate components. PG&E's proposals for standby distribution rates are consistent with the California Public Utilities Commission's (CPUC or Commission) guidance in Decision (D.) 01-07-027. As discussed in Chapter 1 of this exhibit, a key objective of PG&E's standby rate design proposal is to use marginal cost relationships to set distribution and generation rates, balanced with other objectives such as rate stability. PG&E proposes to maintain the existing standby rate structure, but will revise values to reflect the revised seasons and time-of-use (TOU) periods set forth in Exhibit (PG&E-9), Chapter 12, and marginal cost relationships, as practicable.

PG&E provides standby service under Schedule S to customers whose non-utility source of generation is capable of regularly and completely serving their entire electrical load. The largest portion of the load currently served by PG&E under Schedule S (approximately 89 percent) is comprised of customers who take service at transmission service voltages. Schedule S includes customer charges, reservation and TOU energy charges, and all applicable utility charges, terms and conditions for those customers whose non-utility source of generation is capable of regularly and completely serving their entire electrical load.

A limited number of customers require "supplemental" standby service from PG&E. Supplemental standby service is provided to customers who rely on non-utility sources of generation for only a portion of their total load. Under this type of standby service, the customer pays the standby reservation charge from Schedule S only for that portion of its load that is ordinarily supplied by the non-utility generation resource, but pays all other charges under the terms and conditions of the otherwise-applicable rate schedule.[1] The following table summarizes the number of customers taking standby service in 2015 under Schedule S.

TABLE 9-1
STANDBY CLASS
RECORDED 2015

Line No.	Schedule	Description	Average Number of Accounts	Annual Sales	Average Annual kWh Per Account
1	S TOU S	Standby Service (Secondary)	45	2,144,109	47,647
2	S TOU P	Standby Service (Primary)	142	28,201,641	198,603
3	S TOU T	Standby Service (Transmission)	203	478,211,817	2,355,723
4	S TOU	Total Standby (Schedule S)	390	508,557,567	1,303,994

The remainder of this chapter is organized as follows:

- Section B – Sets forth rate design for distribution and generation rate components
- Section C – Conclusion

Appendix B of this exhibit, “Present and Proposed Rates,” contains PG&E’s present and proposed illustrative total and unbundled standby rates.

B. Rate Design

After distribution, PPP and generation revenue is allocated, rates are calculated to collect the assigned revenue for each class and schedule.[2] This section describes PG&E’s proposals for setting the distribution and generation rate components for the standby service tariff, Schedule S. PPP rates for Schedule S are designed in accordance with the guidelines described in Chapter 1, “Revenue Allocation and Rate Design Policy,” of this exhibit.

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[1] Demand charges billed under the terms of the otherwise-applicable rate schedule are reduced by the amounts paid for reservation capacity under Schedule S, in those instances where it is demonstrated that the maximum demand during a given billing cycle was attributable to non-operation of the customer’s generator.

[2] PPP rates are set in accordance with the guidelines set forth in Chapter 1 of this exhibit. Transmission rates are Federal Energy Regulatory Commission jurisdictional and are not subject to change in this proceeding.

1. Distribution Charges

Standby distribution costs will be collected through a combination of customer charges, energy and reservation charges. PG&E proposes to use the same basic rate design that is used for commercial and industrial rates. Consistent with long established practice and to maintain stable relationships across voltages, PG&E combines the billing determinants and marginal costs for standby loads served at primary and secondary distribution voltages before designing distribution energy and reservation charges for these customers.

a. Customer Charge

Customer charges, which are fixed charges per meter per day, are set forth in Schedule S. Customer charges for Schedule S have historically been set at the same levels as applied under the otherwise applicable rate schedule. PG&E proposes to continue this practice, and thus sets the standby customer charges at the same levels as recommended for the otherwise-applicable rate schedules, as presented in Chapter 5, "Small Light and Power Rates" and Chapter 6, "Medium and Large Light and Power Rate Design," of this exhibit.[3]

b. Energy and Reservation Charges

As in the past, PG&E proposes to assign the peak demand-related share of distribution costs to energy charges.[4] In this proceeding, however, PG&E proposes to change the TOU periods for Schedule S to

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[3] PG&E proposes to retain the Schedule S basic service fee of $5 per month for residential customers, and proposes to adopt the proposed AG-B customer charge for agricultural customers, which is $27.87 per month, assessed on a daily equivalent basis. PG&E also proposes changes to the "Reduced Customer Charge" as provided in Special Condition 3 of Schedule S to reflect the updated marginal customer access costs and the proposed customer charges on the otherwise applicable schedules. The revised "Reduced Customer Charges" are shown in Appendix B.

[4] D.01-07-027, mimeo, p. 65. Primary distribution marginal capacity costs are determined based on peak-related peak capacity allocation factors and are assigned to energy for recovery in standby rates.

those TOU periods described in Exhibit (PG&E-9), Chapter 12.[5] Accordingly, PG&E has assigned the peak-related distribution costs to the new TOU periods and recommends allocating the summer and winter shares of these peak-related costs based on marginal cost differentials by TOU period. PG&E proposes to set distribution peak prices and partial-peak prices in the summer at the same level in recognition that PG&E's distribution peak occurs over a much broader range of hours than the generation system. Off-peak costs and any residual distribution revenue are then allocated to the distribution reservation charge.[6] PG&E also proposes to retain the seasonal and TOU differentials (on a cents per kilowatt-hour (kWh) basis) adopted by this decision in rates implemented in the future for revenue requirement changes.

In D.15-08-005, the CPUC approved a settlement on standby rates. In that settlement, the distribution portion of the reservation charge was increased in steps. The last step will be implemented on January 1, 2017. For purposes of evaluating the rate design, PG&E has assumed that the final stepped increase in the reservation charge has occurred and measures changes recommended herein relative to that change.

The final increase of the distribution reservation charge would increase the level of that charge up to $2 per kilowatt (kW) per month (with commensurate reductions to distribution energy rates), not including any revenue requirement changes. As of October 1, 2016, the level of the charge was $4.21 per kW per month of reservation capacity. Absent change in revenue requirement, the level of distribution reservation charge on January 1, 2017 will increase up to $6.21 per kW

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5 The summer season begins on June 1 and continues through September; the winter season is all remaining months. The peak period applies in all days of the week in both seasons and is 5 p.m. through 10 p.m. The partial peak in the summer also applies in all days of the week from 3 p.m. to 5 p.m. and from 10 p.m. to midnight. There is no partial-peak period in the winter. All other hours in the summer and the winter are off peak except for the super off peak which applies from 10 a.m. to 3 p.m. all days of the week in March, April and May.

6 For transmission-voltage standby customers, distribution charges are derived only from marginal customer costs. As such, transmission-voltage customers will pay customer charges set as described in sub-section (a.) above; the remainder of their allocated distribution revenue will be collected in the reservation charge.

per month of reservation capacity, provided that the resulting distribution energy rates are not less than zero. Based on the current distribution revenue allocated to these schedules, the target level of this charge would be approximately $7 per kW per month of reservation capacity. In light of the recent increases to these charges, PG&E requests a moderate change which would add an additional $0.50 kW per month of reservation capacity to the charge (not including any changes to revenue requirement), with commensurate equal cent per kWh reductions to distribution energy rates beginning on January 1, 2019, provided however, that the resulting distribution energy rates are not less than zero.

2. Generation Charges

Standby generation costs will be collected through a combination of energy and reservation charges. Like distribution rate design, PG&E proposes to combine the billing determinants and marginal costs for standby loads served at primary and secondary distribution voltages before designing generation energy and reservation charges for these customers.

a. Energy Charges

PG&E proposes to collect the energy-related share of the total generation revenue assigned to Schedule S in TOU energy charges. The new TOU periods proposed for distribution will also be used for generation rates. PG&E has assigned the energy related share of generation costs to the new TOU periods and recommends maintaining marginal costs differentials by season and TOU period. Winter energy rates are then adjusted to provide for the super off-peak period, as described in Chapter 1 of this exhibit, to develop final winter energy prices for the peak, off-peak and super off-peak periods. Finally, PG&E proposes to retain the seasonal and TOU differentials (on a cents-per-kWh basis) adopted by this decision in rates implemented in the future for revenue requirement changes.

b. Reservation Charges

As in past the 2014 GRC, PG&E proposes to use the capacity-related share of the assigned generation revenue for Schedule S to set the generation component of the standby reservation charge.

C. Conclusion

PG&E's rate design proposal as set forth in this chapter results in substantial changes to reservation and energy charges for standby customers at the primary and secondary voltage with very little change in rates for standby customers served at transmission voltage. PG&E requests that the Commission approve its standby rate design proposal.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

TOU PERIOD CUSTOMER INSIGHTS AND IMPLEMENTATION

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
TOU PERIOD CUSTOMER INSIGHTS AND IMPLEMENTATION

A. Introduction

Pacific Gas and Electric Company (PG&E) has conducted extensive customer research over the past few years on residential customer preferences for different rate plan configurations. As part of this proceeding, PG&E extended this research to small and medium business (SMB) customers[1] to explore their preferences for time of use (TOU) rate plan structures. In early 2016, Hiner and Partners (Hiner) was retained by PG&E to conduct a survey with 1,513 PG&E SMB customers to determine preferences regarding TOU rate structures.[2] Specifically, customer preferences were observed for various TOU rate structure attributes including: peak period hours, days of the week with peak period hours, number of summer TOU periods (partial-peak – three periods, no partial-peak – two periods), a super off-peak period (or “springtime credit”) and summer months. The survey gathered two types of customer responses: (1) preferences for TOU rate structure attributes in isolation; and (2) trade-offs between different levels of the attributes.

The completed analysis and final Hiner Report, dated June 23, 2016, was, unfortunately, not available until after PG&E had to select the updated non-residential TOU periods it would propose in order to be able to run bill impact analyses and prepare testimony. Thus, the TOU periods proposed in Exhibit 9, Volume 1, Chapter 12—with a peak period from 5 p.m. – 10 p.m., partial-peak periods from 3 p.m. – 5 p.m. and 10 p.m. – 12 midnight, a peak period all days of the week, and a springtime super off-peak period from 10 p.m. – 3 p.m. during March, April and May – were determined before the results of this study were available.

PG&E’s position is that, especially for mandatory non-residential TOU rates, the primary driver of TOU period selection should be marginal generation costs,

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1 SMB customers include not only small and medium sized commercial enterprises, but also agricultural (Ag) customers.

2 The complete report and questionnaire are included in Appendix H to Exhibit (PG&E-8).

which plainly supports a 5 p.m. – 10 p.m. peak period.[3] While customer preferences should then also be considered, they should play a secondary role, and be used to refine the cost-based results where possible, in a manner that is not significantly inconsistent with the cost-based hour selection.

For optional rates, somewhat more flexibility might be warranted, in order to make the optional schedule more attractive to customers to achieve greater enrollment and load shifting. TOU periods should still generally align with generation cost data to encourage customers to shift usage away from truly high cost hours, in order to ensure system benefits and reduced costs for all customers.

Thus, PG&E's primary principle is that TOU periods and rates should be cost based;[4] but, as a secondary matter, that the design of those rates should encourage load shifting, be relatively stable, and be understandable. Although these survey results were not available until after PG&E developed its cost-based proposal for a 5 p.m. – 10 p.m. peak period for non-residential customers, the proposal aligns well with the survey results as discussed below.

By presenting these Hiner Report results, PG&E hopes to begin a dialog with other parties, hear their perspectives, and review their formal proposals. PG&E reserves the right to refine its proposals, as might be appropriate, in the future, including in its rebuttal testimony in this proceeding.

B. Summary of Key Findings

The key findings of the June 2016 Hiner Report that may be relevant to this proposal include:

1. Overall Preferences for TOU Rate Structure Attributes Did Not Vary Among SMB Respondent Segments[5]

SMB customers generally prefer:

- Longer peak period hours starting earlier in the day;
- Peak periods all seven days of the week;

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3 See Exhibit (PG&E-8), Chapter 12 for PG&E's specific non-residential TOU Time Periods proposal.

4 See Exhibit (PG&E-8), Chapter 1 for cost-based rate design methodology.

5 See pp. 8-9 of this Chapter for definitions of respondent segment groupings of North American Industry Classification System (NAICS) codes.

- Two TOU periods without a partial-peak period in the summer;
- A springtime super-off-peak period; and
- A shorter four-month summer season rather than a 6-month summer season.

2. Peak Period Hours and Days of the Week With Peak Hours Were the Strongest Drivers of SMB Customer Choice of TOU Rate Plan

a) *Peak period hours* were the most important factor driving respondents' preferred TOU rate. Once all other factors including kilowatt-hour (kWh) prices were included in the decision, customers preferred the peak period hours that started earlier and were longer:

- Initial Questioning. SMBs had the highest preference for a 12 noon – 6 p.m. peak period and a 6 p.m. – 9 p.m. peak period (the shortest time period), each selected by 23 percent of respondents. If a noon to 6 p.m. peak period was not available,[6] a 6 p.m. – 9 p.m. peak period was most preferred by 27 percent of respondents.
- Conjoint Trade-Off Results. Customers preferred a 4 p.m. – 9 p.m. and 4 p.m. – 10 p.m. peak period equally. A 5 p.m. – 10 p.m. peak period was the next most preferred option. A 6 p.m. – 9 p.m. peak period was least preferred.

b) *Days of the week with peak hours* was the second most important factor driving customer's preferred TOU rate. Customers preferred peak hours occurring all seven days of the week:

- Initial Questioning. SMB customers had stronger preference for peak hours to occur all week (7 days) rather than only on weekdays (5 days – Monday through Friday) by a margin of 3:2 (32% vs. 22%).

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6 Although PG&E included a 12 noon – 6 p.m. peak period in this survey, it did so only because that is the current TOU period. It is clear from showings by PG&E and Office of Ratepayer Advocates in PG&E's 2015 Rate Design Window proceeding (A.14-11-014), as well as by the California Independent System Operator (CAISO) in the TOU Periods Order Instituting Rulemaking, that the actual peak period with the highest generation costs has shifted later in the day based on the significant increase in renewables (especially solar), due to California's aggressive Renewables Portfolio Standard. A 12 noon – 6 p.m. peak period is no longer aligned with high cost hours, thus is not considered by PG&E to be a viable option to consider proposing here.

- Conjoint Trade-Off Results. In the context of other factors including kWh prices, customers continued to prefer peak hours all week rather than only on weekdays (M-F), a result that was consistent with their initial preferences.

c) *Number of summer TOU periods* was the third most important factor driving customer choice. Although less important that peak period hours and days of the week, SMB customers preferred a simpler 2-period on-peak and off-peak structure in the summer, rather than a structure that also included a partial-peak period:

- Initial Preferences. SMB customers had higher preference for two summer TOU periods, without a partial-peak period, by a margin of 3:2 (29% vs. 18%).
- Conjoint Trade-Off Results. Customer preferences were similar to the initial choice of two summer TOU periods per day.

d) *A springtime credit* (super off-peak period) was the least important driver of customer choice. Initially, customers preferred no springtime credit during months where oversupply and potential negative pricing events are emerging. However, once all other factors including kWh prices were included in the decision, customers leaned more towards having a springtime super off-peak credit.

- Initial Questioning. When given the option of a springtime super off-peak period, or no springtime super off-peak period, customers preferred no springtime super off-peak period by a margin of about 4:3 (22% vs. 17%).
- Conjoint Trade-Off Results. Customers preferred the springtime super off-peak period over no springtime super off-peak period, contrary to their initial preferences.

e) Fewer *summer months*, June-September, with slightly higher peak prices were preferred more (30%) than summer months of May-October (24%) with slightly lower peak prices.

3. Although Overall Preferences for TOU Rate Structure Attributes Did Not Vary Among SMB Respondent Segments, Among Some Segments, There Were Noticeable Variations in Degree of Preference for Peak Period Hours and Days of the Week With Peak Hours

a) Peak Period Hours

- Ag SMB respondents had stronger preferences for peak periods starting earlier, at 4 p.m., and showed a strong negative preference for a 6 p.m. – 9 p.m. peak period;
- Retail and Education/Health SMB respondents showed relatively weaker preferences for peak periods starting earlier at 4 p.m. and somewhat stronger preferences for a later end time of 10 p.m.; and
- Construction/Manufacturing/Wholesale/Transportation and Financial/Technical/Government SMB respondents preferred an earlier start time of 4 p.m., but a longer peak period ending at 10 p.m.

b) Days of Week with Peak Hours

- Ag SMB respondents had weaker preferences for peak hours all week versus only Monday through Friday.
- Education/Health, Retail and Construction/Manufacturing/Wholesale/Transportation SMB respondents had stronger preferences for peak hours all week versus Monday through Friday

There was very little variation in preferences among the segments for partial peak and springtime super off-peak periods, with the overall preferences being against a partial peak in summer and in favor of a springtime super off-peak.

4. PG&E's Cost-Based Proposal for Non-residential TOU Time Periods Aligns With Customer Preferences

In Figure 10-1 below, PG&E presents a comparison of non-residential customer preferences for TOU time periods from the Hiner Study, with PG&E's proposal for non-residential TOU time periods.

FIGURE 10-1
ALIGNMENT OF PG&E'S TOU TIME PERIOD PROPOSAL WITH CUSTOMER PREFERENCES

TOU Rate Structure Attribute	Current Structure	Customer Preference Survey Results	PG&E Proposal
Peak Period Hours	12 noon – 6 p.m.	4 p.m. – 9 p.m.	5 p.m. – 10 p.m.
Days of the Week With Peak Hours	Monday through Friday	All Days, Monday through Sunday	All Days, Monday through Sunday
Number of Summer TOU Periods	Three Summer TOU Periods (except for small Ag which does not have a Summer Partial Peak period)	Two Summer TOU Periods	Ag: Two Summer TOU Periods Non-Ag: Three Summer TOU Periods
Springtime Credit (Super Off-Peak Period)	None	Springtime Credit Included, March through May	Ag: Springtime Credit Included, April and May Non-Ag: Springtime Credit Included March through May
Summer Months	May through October	June through September	June through September

PG&E's believes its cost-based proposals of a 5 p.m. – 10 p.m. peak period, and a summer partial-peak period for non-Ag customers only, and a springtime super-off-peak credit are justified, although they do not exactly align with customer preferences. The detailed supporting analysis presented in Exhibit (PG&E-9), Chapter 12 shows that high cost hours for PG&E have now moved to 5 p.m. – 10 p.m., and that partial-peak periods and a super off-peak period are also important for achieving cost-based price signals for customers. In Chapter 7 on Ag rate design, PG&E presents its analyses supporting the differences in the TOU time periods PG&E is proposing for its Ag customers.

C. Research Supporting TOU Periods Proposal

In early 2016, Hiner & Partners was retained by PG&E to conduct a survey of 1,513 PG&E customers to determine non-residential customer preferences regarding TOU rate structures. The remainder of this chapter provides details on the design and key findings of that survey. The complete report and questionnaire are included in Appendix H, included with Exhibit (PG&E-8).

1. Survey Design

Questionnaire topics addressing SMB customer TOU rate structure preferences included:

- Number of TOU time periods
- Days of the week to which peak pricing applies
- Start and stop times, and duration of the peak period
- Length of the summer season
- Springtime super-off peak period

The survey included a choice exercise to gather data as part of a conjoint analysis (choice-based questions within a conjoint analysis design). The conjoint analysis framework decomposed a "complete" rate plan into specific attributes (e.g., peak and partial-peak hours, peak days of the week, summer periods (partial peak), springtime super off-peak, cost-based volumetric per kWh prices). Each attribute consists of a range of "levels" (e.g., peak period: 6 p.m. – 9 p.m.; 4 p.m. – 9 p.m.; 5 p.m. – 9 p.m.; and 5 p.m. – 10 p.m.). The TOU rate plan attributes and levels that were included in the choice exercise are shown in Table 10-1 below:

TABLE 10-1
TOU RATE PLAN ATTRIBUTES AND LEVELS

Attributes	Levels
Summer On-Peak Hours	6 p.m. – 9 p.m. 4 p.m. – 9 p.m. 5 p.m. – 10 p.m. 4 p.m. – 10 p.m.
Days with Peak Hours	Monday through Friday All Days of the Week
Summer Periods (Partial Peak)	On-Peak, Partial-Peak, Off-Peak On-Peak, Off-Peak
Springtime Off-Peak Credit of 5 cents (Super Off-Peak)	Springtime season with Super Off-Peak period No Super Off-Peak period

Respondents were given 8 "choice sets." Each choice set included three different rate plan options. Each rate plan option in turn was a random composition of one level for each attribute, combined with a set of cost based rates for that particular set of attributes. Figure 10-2 below provides an illustrative example of a choice set shown to a respondent:

FIGURE 10-2
EXAMPLE CHOICE SET – 3 RATE PLAN OPTIONS

The conjoint analysis of the resulting 12,104 “choices”[7] presented to respondents identified the: (a) relative importance of each attribute in their decision making; and (b) the “utility” or impact of different levels within an attribute on respondent decision making. These measurements for each attribute were then used to construct a model that estimates customer preference among any number of “complete rate plan” combinations of attributes and levels. The conjoint exercise forced respondents to make a choice between three different combinations of rate attributes. This allowed insight into how respondent preferences change when they must make

7 1,513 respondents x 8 choice sets = 12,104.

trade-offs between levels of attributes. In addition, there were no options for "no preference" or "not sure" which provided a more realistic view of what preferences would be if a choice was required.

2. Survey Sample

Respondents were grouped by NAICS codes to create sample subgroups (segments). The study sample[8] size and industry distribution (based on NAICS) of participants, as well as the margins of error associated with each sample subgroup at 90 percent confidence level, are shown in Table 10-2 below.[9]

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[8] The survey was administered via an email link sent to 51,665 SMB customers. Screening questions identified customers who review and pay a PG&E bill. A total of 3,378 customers clicked the email link, 2,924 moved past the landing page, 1,579 completed the survey and 66 were removed in quality assurance review, for a total of 1,513 surveys used in the analysis. Although customers who respond to an online survey are self-selected and thus may not necessarily be "representative" of the entire business population, Hiner monitored the NAICS classification codes of survey respondents so that the survey sample approximated the customer population on this key variable.

[9] For example, a margin of error of +/- 2.1 percent means that the true population percentage response to a question would be within plus or minus 2.1 percent of the reported percentage from the survey sample 90 out of 100 times.

TABLE 10-2
TOU CONJOINT SURVEY SAMPLE

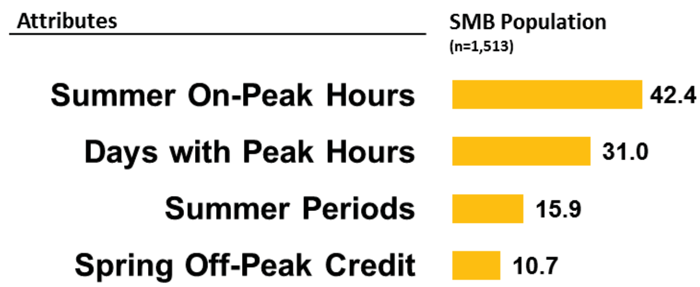
Segment	NAICS Subcategories	Sample Size	Margin of Error +/-
Total		1,513	2.1%
Ag	11 Agriculture, Forestry, Fishing and Hunting	147	6.8%
Retail	44-45 Retail Trade	191	5.9%
Financial/ Technical/ Professional/ Government	52 Finance, Insurance 53 Real Estate, Rental, Leasing 55 Management of Companies and Enterprises 51 Information 54 Professional, Scientific, and Technical 56 Administrative, Waste Management 92 Public Administration	285	4.8%
Education/ Health	61 Educational Services 62 Health Care and Social Assistance	165	6.4%
Other Services	81 Other Services – Repair, Personal, Laundry, Religious, Civic	284	4.9%
Hospitality/ Restaurants/ Entertainment	72 Arts, Entertainment and Recreation 71 Accommodation and Food Services	203	5.8%
Construction/ Manufacturing/ Wholesale/ Transportation	21 Mining, Quarrying, and Oil and Gas Extraction 23 Construction 31-33 Construction 42 Wholesale Trade 48-49 Transportation and Warehousing	208	5.7%

D. SMB Customer TOU Rate Plan Preferences

1. Relative Importance of Rate Structure Attributes

As shown in Figure 10-3 below, the two primary drivers of choice of rate plans were summer on-peak hours (42.4) and days with peak hours (31). The remaining two attributes – summer periods (partial peak) and springtime super off-peak credit were less important and had a much lower impact on rate choice with importances of 15.9 and 10.7, respectively.

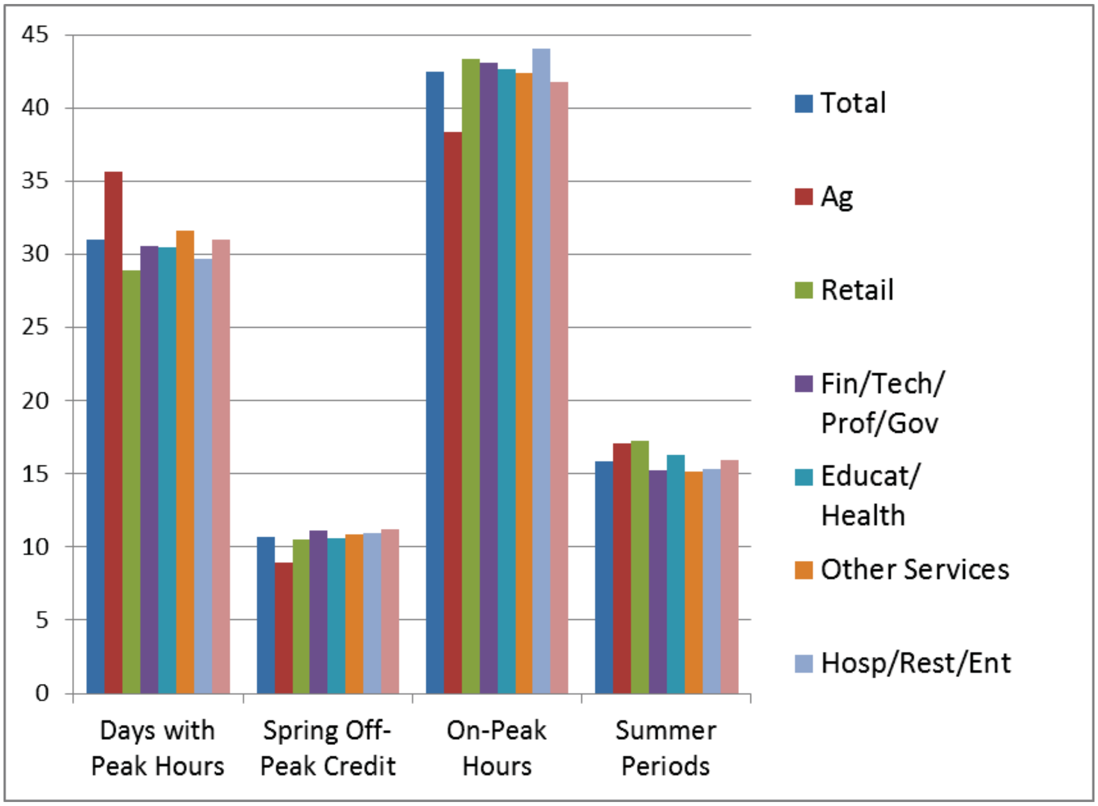
FIGURE 10-3
AVERAGE IMPORTANCES OF RATE PLAN ATTRIBUTES



As shown in Figure 10-4 below, there were some variations among the segments in average importances of rate plan attributes:

- Ag respondent choice of rate plan was influenced relatively more by days with peak hours, and less by the actual on-peak hours and springtime super-off peak credit than for the other segments;
- Hospitality/Restaurants/Entertainment respondent choice was influenced relatively more by the on-peak hours; and
- Retail respondent choice of rate plan was influenced slightly more by on-peak hours and summer periods (partial peak), and less by days with peak hours.

FIGURE 10-4
AVERAGE IMPORTANCES OF TOU RATE PLAN ATTRIBUTES



2. TOU Attribute Preferences

a. SMB Customers Prefer Earlier Peak Periods

After receiving educational information about TOU, respondents indicated their preference regarding the number of peak hours. Figure 10-5 below shows that 23 percent of respondents initially preferred the current peak period of noon to 6 p.m. and 23 percent of respondents preferred a shorter peak period of three hours, from 6 p.m. – 9 p.m. 20 percent of respondents preferred a longer peak starting at 4 p.m., and 16 percent of respondents preferred a longer peak starting at 5 p.m. Ten percent of respondents indicated no preference among the options shown while 18 percent were not sure how the different options would impact their business. Ag respondents had stronger preference for the current peak period of noon to 6 p.m. and Education/Health respondents had a stronger preference for the later 6 p.m. – 9 p.m. and 5 p.m. – 10 p.m. peak periods. Construction/Manufacturing/Transportation respondents had a relatively stronger preference for a longer 6-hour peak period from 4 p.m. – 10 p.m.

When noon to 6 p.m. was eliminated as an option, the relative preferences among the remaining options were similar, with the most popular choice being 6 p.m. – 9 p.m. The current 12 noon – 6 p.m. peak period option was eliminated in the second part if this question in order to assess preferences among feasible options that were determined to include enough high cost hours.[10]

FIGURE 10-5
TOU: PREFERRED PEAK HOURS

Peak Hours	SMB Population (n=1,513)	Conjoint Preferences	(a) Ag (n=147)	(b) Retail (n=191)	(c) Financial Prof/Gov (n=285)	(d) Education /Health (n=165)	(e) Other Services (n=314)	(f) Hosp/ Rest/Ent (n=203)	(g) Cons/Man /Trans (n=208)
Noon to 6:00 pm (6 hrs)	23%		33% BCDEFG	24%	21%	18%	22%	24%	20%
6:00 pm to 9:00 pm (3 hrs)	23% 27%		16%	26% AG	26% AG	29% AG	23% A	23% A	19%
5:00 pm to 9:00 pm (4 hrs)	5%		6%	4%	5%	5%	5%	5%	6%
4:00 pm to 9:00 pm (5 hrs)	6% 11%		6%	5%	5%	5%	8%	7%	7%
5:00 pm to 10:00 pm (5 hrs)	9% 10%		3%	7% A	11% AF	17% ABCEFG	9% A	6%	9% A
4:00 pm to 10:00 pm (6 hrs)	6% 8%		3%	4%	8% ABEF	5%	4%	3%	10% ABEF
No preference: won't impact business	10% 16%		11%	9%	11%	7%	10%	10%	10%
Not sure of business impact	18% 23%		22% CD	20% D	14%	13%	19% D	22% CD	20% D

Excluding existing noon-6pm
Including existing noon-6pm

Q3.1a: "For your business, which would you prefer?"
Q3.1c: [IF 3.4a=Punch 1] "Among the remaining options, which would you most prefer?"

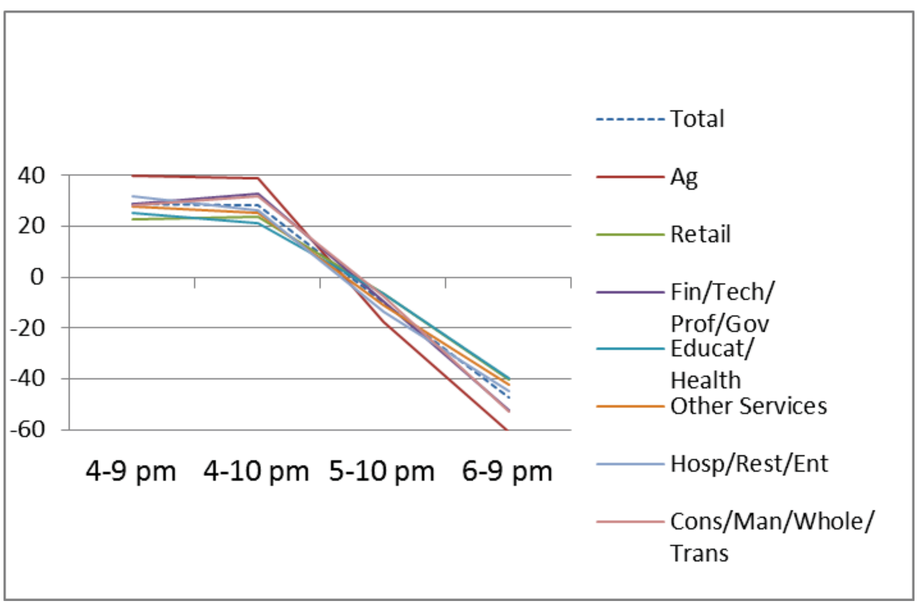
Preferences for peak hours were somewhat different when respondents were provided a "Choice Set" and asked to select among three different rates that included variations of kWh prices, days with peak, springtime super off-peak credit (yes or no) and two or three summer periods. Figure 10-6 below shows that earlier start times were preferred more than later start times. A 6 p.m. – 9 p.m. peak period was the least preferred of all the options, as indicated by the

10 See Exhibit (PG&E-9), Chapter 12.

negative values in the range of -40 to -60. In addition, notably, overall preferences were fairly consistent among segments, with all segments preferring an early start time of 4 p.m., and all segments showing a negative preference for peak periods starting later. However, some differences among segments can be observed:

- Ag respondents showed a stronger preference for peak periods starting earlier at 4 p.m., demonstrated by the highest red line with utility value of ~40 for both 4 p.m. – 9 p.m. and 4 p.m. – 10 p.m.;
- Ag respondents showed a strong negative preference for a 6 p.m. – 9 p.m. peak period;
- Retail and Education/Health respondents showed relatively weaker preferences for peak periods starting earlier at 4 p.m., demonstrated by the lowest blue and green lines slightly above the utility value of 20; and
- Construction/Manufacturing/Wholesale/Transportation and Financial/Technical/Professional/Government respondents preferred an earlier peak period start time of 4 p.m., but a longer period ending at 10 p.m.

FIGURE 10-6
SUMMER ON-PEAK HOURS – PREFERENCES (UTILITY VALUE)



Price levels and price ratio may have been a factor in the shift in preferences for summer on-peak hours away from 6 p.m. to 9 p.m. Price was not included as an attribute in the conjoint model. Only actual cost-based rate values were used in each rate combination, because price is not a variable that can be modified indiscriminately in cost-based rate design. Limiting the kWh prices to cost-based rates precluded a full set of price levels required to appropriately measure the influence of price in the analysis. However, respondents were shown the kWh pricing associated with each combination of levels for the attributes. An analysis of kWh prices associated with each of the tested start and stop times for TOU summer peak hours shows that respondents' overall preference for peak hours is in the same rank order as kWh prices ranging from low to high. Table 10-3 below shows that the 16 rate options with a 6 p.m. – 9 p.m. peak period had a summer on to off-peak average price ratio of 1.68563, compared to a lower ratio of 1.55872 for the 16 rate options with a the most preferred 4 p.m. – 9 p.m. peak period. In other words, respondents had highest preference for the peak hours associated with the lowest kWh prices, and the lowest preference for peak hours associated with the highest preference. A conclusion is that respondents, overall, preferred TOU parameters associated with lower kWh prices.

TABLE 10-3
PRICE LEVEL AND PRICE RATIO AVERAGES BY SUMMER ON-PEAK HOUR OPTION

Line No.	On-Peak Hour Option	# of Rate Combinations	Summer Average On-Peak	Summer Average Off-peak	Summer Average Price Ratio
1	6 p.m. – 9 p.m.	16	0.39460	0.23511	1.68563
2	5 p.m. – 10 p.m.	16	0.37806	0.22892	1.65767
3	4 p.m. – 10 p.m.	16	0.36242	0.22706	1.60185
4	4 p.m. – 9 p.m.	16	0.35840	0.23081	1.55872

b. SMB Customers Prefer Peak Periods Seven Days a Week, Monday through Sunday

As shown in Figure 10-7 below, about a third (32 percent) of respondents preferred peak periods that occur seven days a week, Monday through Sunday, while one in five (22 percent) preferred they occur on just the five weekday Monday through Friday period. Ag respondents were more likely to want weekday-only peak periods, while Education/Health respondents were more likely to prefer a peak period seven days a week. Hospital/Restaurants/Entertainment respondents were more likely to be unsure of how these differences would impact their business.

FIGURE 10-7
TOU: PREFERRED DAYS PER WEEK WITH PEAK HOURS

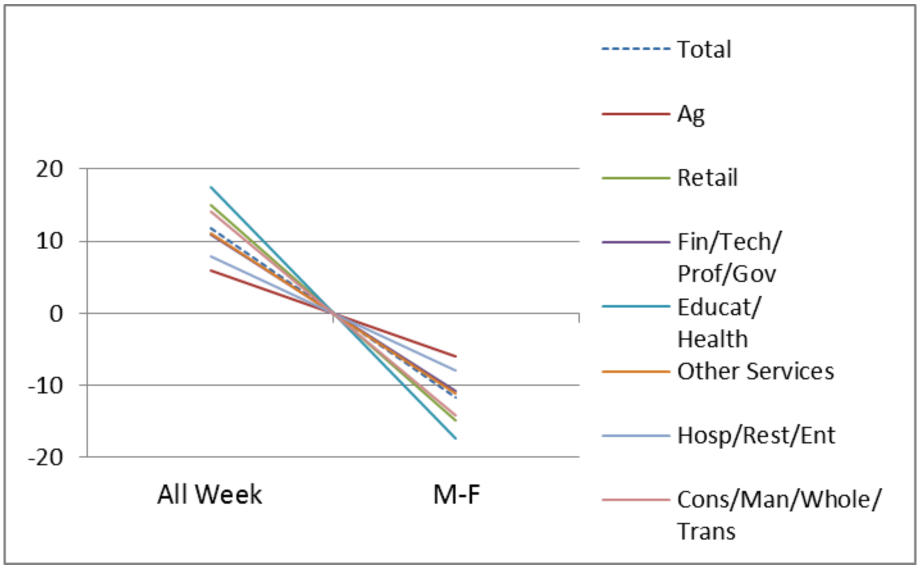
Day Per Week with Peak Hours	SMB Population (n=1,513)	Conjoint Preferences	NAICS (a) Ag (n=147)	(b) Retail (n=191)	(c) Financial Prof/Gov (n=285)	(d) Education /Health (n=165)	(e) Other Services (n=314)	(f) Hosp/ Rest/Ent (n=203)	(g) Cons/Man /Trans (n=208)
Weekdays (M-F, 5 days)	22%		29% BDEFG	18%	26% BD	19%	21%	21%	20%
All week (M-S, 7 days)	32%		28%	29%	35% F	43% ABCEFG	30%	26%	32%
No preference: won't impact business	17%		17%	21% D	17% D	12%	19% D	17%	16%
Not sure of business impact	29%		27%	31% C	22%	27%	30% C	36% ACD	32% C

Q3.3a: "For your business, which would you prefer?"

Preferences for peak period days were similar when respondents were provided a "Choice Set" and asked to select among three different rates that included variations of kWh prices, days with peak, super off-peak (yes or no) and two or three summer periods. Figure 10-8 below shows that a peak period all days of the week was preferred over a peak period only on Monday through Friday. In addition, overall preferences were consistent among segments, with all segments preferring a peak period all days of the week. However, some differences among segments can be observed:

- Ag respondents had weaker preferences for peak hours all week versus Monday through Friday; and
- Education/Health and Hospitality/Restaurants/Entertainment had stronger preferences for peak hours all week versus Monday through Friday.

FIGURE 10-8
DAYS PER WEEK WITH PEAK HOURS – PREFERENCES (UTILITY VALUE)



c. SMB Customers Prefer Two TOU Periods Without a Partial Peak Period During the Summer

As shown in Figure 10-9 below, SMB customers had higher preference for two TOU periods, without partial peak during summer, by a margin of 3:2 (29% vs. 18%).

FIGURE 10-9
TOU: PREFERRED NUMBER OF TOU PERIODS IN SUMMER

			NAICS						
Number of TOU Periods	**SMB Population** (n=1,513)	**Conjoint Preferences**	(a) **Ag** (n=147)	(b) **Retail** (n=191)	(c) **Financial Prof/Gov** (n=285)	(d) **Education /Health** (n=165)	(e) **Other Services** (n=314)	(f) **Hosp/ Rest/Ent** (n=203)	(g) **Cons/Man /Trans** (n=208)
2 TOU Periods in Summer	**29%**		37% BCE	26%	27%	36% BCE	25%	30%	29%
No change: Summer (3), Winter (2)	**18%**		21% B	14%	19%	16%	18%	18%	19%
No preference: won't impact business	**14%**		10%	16%	18% AG	16%	14%	14%	12%
Not sure of business impact	**38%**		32%	45% ACD	36%	32%	42% AD	38%	40% D

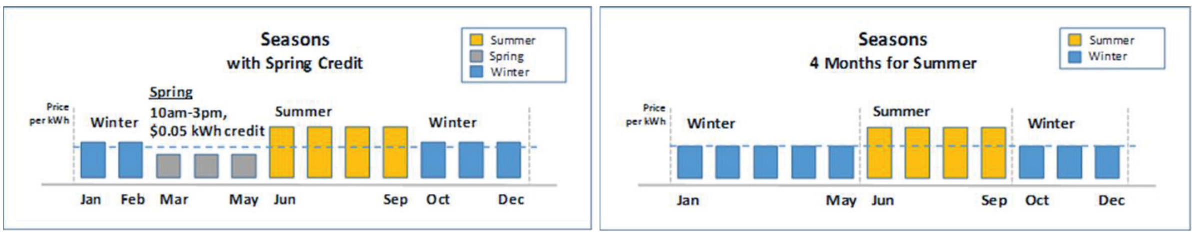
Q3.2b: "For your business, which would you prefer?"

Preferences were similar when respondents were provided a "Choice Set" and asked to select among three different rates that included variations of kWh prices, days with peak, super off-peak (yes or no) and two or three summer periods. In addition, overall preferences were consistent among segments, with all segments preferring two TOU periods without a Partial peak during summer.

d. SMB Customers Are Open to a Springtime Super Off-Peak Period

Figure 10-10 below is the graphic that was provided to respondents to educate them about a potential springtime super off-peak period.

FIGURE 10-10
EDUCATIONAL INFORMATION: SPRINGTIME CREDIT (SUPER OFF-PEAK PERIOD)



As shown in Figure 10-11 below, after respondents reviewed the educational information about the springtime super off-peak period, about one in five (22 percent) preferred no springtime super off-peak period. The other four out of five respondents preferred a springtime super off-peak period (17 percent), had no preference (22 percent) or were unsure how the springtime super off-peak period would impact their business (38 percent).

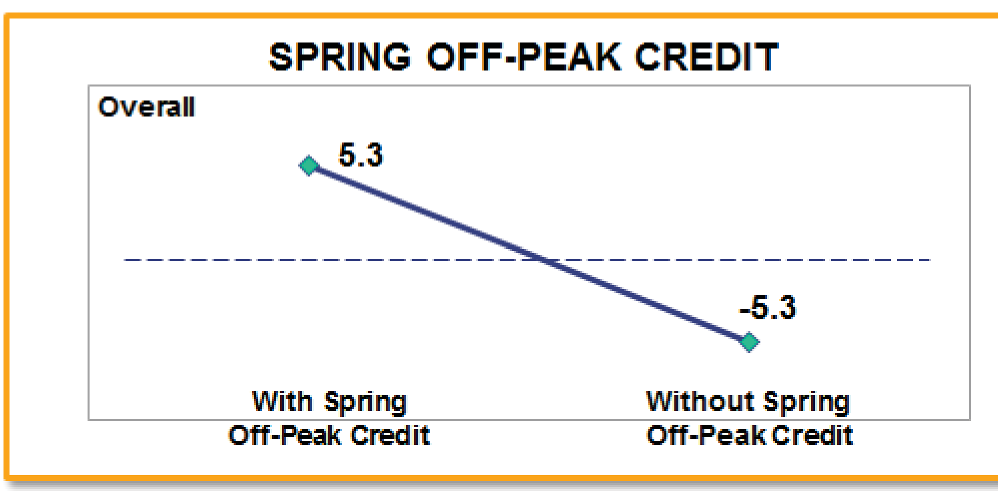
FIGURE 10-11
TOU: SPRINGTIME CREDIT (SUPER OFF-PEAK PERIOD)

		NAICS						
Summer Length	**SMB Population** (n=1,513)	(a) **Ag** (n=147)	(b) **Retail** (n=191)	(c) **Financial Prof/Gov** (n=285)	(d) **Education /Health** (n=165)	(e) **Other Services** (n=314)	(f) **Hosp/ Rest/Ent** (n=203)	(g) **Cons/Man /Trans** (n=208)
Springtime: 10:00-3:00pm $0.05 reduction with slightly higher prices at all other winter times	**17%**	21% F	15%	19%	20%	15%	14%	16%
No springtime: 10:00-3:00pm reduction, so winter rates would not change	**22%**	23%	21%	22%	22%	20%	27% E	23%
No preference: these differences won't impact my business	**22%**	22%	21%	26% F	20%	24%	19%	21%
Not sure how these differences would impact my business	**38%**	33%	42% AC	32%	38%	41% C	40% C	40% C

Q3.2b: "For your business, which would you prefer?"

Preferences were opposite when respondents were provided a "Choice Set" and asked to select among three different rates that included variations of kWh prices, days with peak, super off-peak period (yes or no) and two or three summer periods. Figure 10-12 below shows that the super off-peak period was preferred. Although the overall importance in choice of rate plan was low, respondents preferred their rate plan to include a super off-peak period.

FIGURE 10-12
TOU: SUPER OFF-PEAK PERIOD



Overall preferences were consistent among segments, with all segments preferring two TOU periods without a partial peak during summer. Little variation was observed among the segments in preference.

e. SMB Customers Prefer Fewer Summer Months With the Highest Peak Prices

As Figure 10-13 below shows, respondents had the highest preference (30 percent) for a four-month summer period (June-September). About the same percentage of respondents were not sure how these changes would affect their business and 16 percent had no preference. The remaining respondents (24%) preferred the current definition of the summer season from May-October.

FIGURE 10-13
TOU: PREFERRED PEAK MONTHS OF THE YEAR

		NAICS						
Summer Length	**SMB Population** (n=1,513)	(a) **Ag** (n=147)	(b) **Retail** (n=191)	(c) **Financial Prof/Gov** (n=285)	(d) **Education /Health** (n=165)	(e) **Other Services** (n=314)	(f) **Hosp/ Rest/Ent** (n=203)	(g) **Cons/Man /Trans** (n=208)
6 month summer (May-Oct)	**24%**	33% BCDEFG	22%	23%	23%	22%	24%	23%
4 month summer (Jun-Sep)	**30%**	35% B	26%	28%	35% BEG	27%	38% BCEG	27%
No preference: Won't impact business	**16%**	10%	18% ADF	20% ADF	12%	18% ADF	11%	18% ADF
Not sure of business impact	**30%**	22%	34% A	29%	30%	33% A	27%	32% A

Q3.2a: "For your business, which would you prefer?"

E. Implementation

1. Customer Outreach for TOU Time Period Change and New Agricultural Rates

PG&E plans to implement a multi-channel campaign that draws from the experience and learnings of the time-varying pricing transition for non-residential customers over the last five years. The campaign will provide customers with the ongoing education necessary to drive awareness and understanding of TOU time period changes and new Ag rates, along with rate analyses and recommended actions that prepare customers to respond appropriately when TOU time periods and Ag rates change. Customer education and outreach will use the following strategies:

- Begin general awareness education at least 12 months prior to introduction of new time periods;
- Use multiple touches over the course of this period of at least 12 months prior to the TOU time period and Ag rate changes, to raise customer awareness and understanding;
- Provide outreach through multiple channels to more effectively educate and engage with our customers about the changes; and
- Employ a targeted approach with greater outreach focused on customers that are most likely to see bill increases due to the TOU time period and Ag rate changes, including person-to-person outreach for highly impacted customers.

A large shift in TOU time periods, such as are being proposed in this 2017 General Rate Case (GRC) Phase II, can result in significant impacts on some customer's bills if the customer does not change their usage behavior to better match the new rates. Advance communications will be required to educate customers on the changes and allow them enough time to adjust their business operations and make any desired investments to better enable them to respond to the shifted timing of the peak period and new Ag rates.

For some larger customers, the current non-residential TOU time periods have been in effect for decades. The transition to new TOU periods is likely to pose a greater challenge for customers who will, for the first time in decades, have to consider how they can adjust business operations and shift energy use away from the new higher cost time period. In addition, PG&E is currently in the last stages of transitioning the remainder of its SMB customers to mandatory TOU rates. SMB customers who have recently been transitioned to TOU rates may find the proposed changes to TOU time periods confusing. Both shorter-term TOU customers as well as longer-term ones will need advance education on the new time periods to help them to understand the changes and provide them adequate time to determine how they can adjust their energy use and prepare to do so when the new periods are launched.

2. Customer Transition to New TOU Time Periods

There are several objectives for PG&E's TOU time period transition plan:

- Provide the ability for existing customers to opt-in to new TOU time periods before they become mandatory;
- Avoid misalignment of the TOU peak period and Peak Day Pricing (PDP) critical peak period;
- Minimize customer enrollment on TOU rates with noon to 6 p.m. time period after the California Public Utilities Commission adopts later TOU peak period hours to be implemented over the following 12-18 months;
- Provide stability for customers by allowing them a full 12 months on their current TOU rate before defaulting them to a TOU rate with later hours; and
- Align customer default to rates with later TOU time periods with existing November SMB and March Ag TOU/PDP transition windows.

As the first step in transitioning customers to the new TOU time periods, PG&E plans to introduce optional rates with the new time periods, and encourage customers who can benefit from a later peak period to voluntarily enroll over a six to nine-month period after the introduction of the new optional rates. At the end of that period, and after sufficient education and outreach, the new rates would become mandatory, and all bundled customers with interval usage data that have been on a TOU rate for at least 12 months would be transitioned to them.[11] All defaults will align, to the extent possible, with existing November SMB and March Ag transition windows. Existing customers with less than 12 months on a TOU rate (new customers and customers recently transitioned to TOU) may opt-in to rates with the new TOU hours, but will not be subject to default to rates with the later TOU peak period until they have at least 12 months on their original

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[11] Customers who choose not to transition to a SmartMeter™ (e.g., SmartMeter™ opt-out) or another type of interval meter will remain on appropriate rates. An interval-read meter is required for a customer to be transitioned to a TOU rate.

PG&E also is requesting authority to transition Direct Access/Community Choice Aggregation (DA/CCA) customers with 12 months of interval data off non-TOU rates. (Exhibit (PG&E-8), Chapter 1, page 1-17.) If PG&E's proposal is approved, PG&E would transition these customers to the TOU rate schedules.

TOU rate. New customers will be enrolled on TOU rates with the new time periods when they are available as optional rates.

Table 10-4 summarizes these customer transitions to new TOU time periods.

TABLE 10-4
CUSTOMER TRANSITION TO NEW TOU PERIODS

Customer Type	Options	Notes
Existing TOU Customer With 12 Months on TOU	Opt-in to new TOU time periods when they are available	
	Default to new TOU time periods when they become mandatory	These defaults would be batched and streamlined with the current TOU/PDP November SMB or March Ag transition windows
Existing TOU Customer with less than 12 months on TOU (New Customers or Flat Rate Customers Recently Transitioned to TOU)	Opt-in to new TOU time periods when they are available	
	Default to new TOU time periods after 12 months on TOU	These defaults would be batched and streamlined with the current TOU/PDP November SMB or March Ag transition windows
New Customers/New Flat Rate Customer Transitions after Optional Rates are Available	Must enroll in optional TOU rate with new, later, peak periods	

The proposed PDP critical peak period change from 2 p.m. – 6 p.m. to 5 p.m. – 9 p.m. would be implemented along with the migration of all customers to the new mandatory TOU time periods. Specific outreach will be conducted for existing PDP customers that have opted into the new TOU time periods earlier than when they become mandatory to make the customer aware of their ability to opt-out of PDP and opt-back in once the new critical peak PDP hours are implemented and align with the new TOU time periods.[12]

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[12] Existing PDP customers who remain on PDP and opt into the new TOU time periods before they become mandatory will be subject to PDP peak hours and TOU peak hours that do not align, i.e. the existing PDP peak period of 2 p.m. – 6 p.m. and the new TOU peak hours of 5 p.m. – 10 p.m.

Therefore, PG&E proposes that, after the final decision in this case, any PDP defaults for existing customers still on TOU rates with a 12 noon – 6 p.m. peak period be delayed until the new TOU hours are mandatory and the PDP hours have been changed.[13] Existing customers still on TOU rates with a 12 noon – 6 p.m. peak period whose PDP default date occurs after the decision but before the new TOU hours are mandatory and the PDP hours change, would face misalignment of PDP and TOU peak hours. PG&E's proposal avoids the possibility of confusing customers by switching them between different sets of PDP hours soon after default, if they reach their PDP default date in the period prior to implementation of the new PDP hours.

Table 10-5 summarizes these customer transitions to new PDP critical peak hours.

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[13] D.10-02-032, as modified by D.11-11-008, ordered PG&E to default large, medium and small business customers to mandatory TOU and opt-out PDP. SMB customers with 12 months of interval data would default to mandatory TOU starting November 2012. By November 2014, SMB customers with 12 months of interval data started defaulting to PDP. Under these decisions, PG&E defaults SMB customers to PDP only after they have been on TOU for 24 months. After 2016, PG&E will continue to treat new customers in the customer classes identified in D.10-02-032 and D.11-11-008 as subject to default opt-out PDP when they have 24 months on mandatory TOU. However, to avoid confusing customers before the new TOU peak hours are aligned with the new PDP critical peak hours, PG&E proposes to defer defaulting customers to PDP until all TOU customers are moved to the new TOU peak hours, and the new PDP critical peak hours go into effect.

TABLE 10-5
CUSTOMER TRANSITION TO NEW PDP CRITICAL PEAK HOURS

Alternative Customer Paths		Transition description
Existing PDP Customer	Opts-in to new TOU hours before they become mandatory	Outreach to alert customer to non-alignment of current 2 p.m. – 6 p.m. PDP critical peak hours and new 5 p.m. – 10 p.m. TOU peak hours, and to inform customer of right to opt-out of PDP and later opt-in to PDP when the new 5 p.m. – 9 p.m. PDP critical peak hours are aligned with new 5 p.m. – 10 p.m. TOU peak hours.
Existing PDP Customer	Defaults to new TOU hours when they become mandatory	Transition the customer to new 5 p.m. – 9 p.m. PDP critical peak hours when they go into effect and are in alignment with the new 5 p.m. – 10 p.m. TOU peak hours.
Non-PDP Customer	Opts-in to new TOU hours before they become mandatory	Do not default the customer to PDP until the later of: (a) new 5 p.m. – 9 p.m. PDP critical peak hours and new 5 p.m. – 10 p.m. TOU peak hours are in effect and are in alignment, or (b) 24 months after the customer has been on TOU.
Non-PDP Customer	Defaults to new TOU hours when they become mandatory	Do not default the customer to PDP until the later of: (a) new 5 p.m. – 9 p.m. PDP critical peak hours and new 5 p.m. – 10 p.m. TOU peak hours are in effect and are in alignment, or (b) 24 months after the customer has been on TOU.
New Customer	See Table 10-4 above for new customer TOU enrollment	Do not default the customer to PDP until the later of: (a) new 5 p.m. – 9 p.m. PDP critical peak hours and new 5 p.m. – 10 p.m. TOU peak hours are in effect and are in alignment, or (b) 24 months after the customer has been on TOU.

Summary of PG&E's TOU Time Period Change Transition proposal:

- After GRC 2 decision, delay all PDP defaults until new TOU time periods are mandatory for all customers;
- A customer on a TOU rate with a noon to 6 p.m. peak period for less than 12 months will not be defaulted to a rate with the later TOU time periods; until they have 12 months on their original TOU rate;
- TOU rates with new time periods will be available in 9-12 months from decision:
  - Optional for existing TOU customers; and
  - Mandatory for new customers and flat rate customers scheduled for TOU default;
- TOU rates with new time periods become mandatory for all customers six–nine months after made available as optional rates; and
- New PDP critical peak hours become effective at the same time TOU rates with new time periods become mandatory for all customers and then PDP default resumes.

3. Billing System Changes

See Table 10-6 below for estimated minimum lead-time required to implement the necessary billing system and other operational changes required for the various rate design proposals in this proceeding.

TABLE 10-6
CC&B, MYENERGY, OPOWER & RATE ENGINE CHANGES TIMELINE

Non-Residential	
TOU Time Period Change (all non-res schedules)	9-12 months
AG Rate Redesign – A/B/C New AG Rates/AG Rate Transitions (old rates and new rates concurrently in place), Eliminate Peak Demand Charge on all Ag B options, Revision and re-opening of AGR, initiate new Demand Charge Limiter.	9-12 months
Streetlights - Eliminate Light Emitting Diode (LED) replacement cost required and LED conversion adder by standard lamps.	4-6 months
New Optional Demand Charge Rate (Residential)	4-6 months
PDP Critical Peak Period Change	3-5 months
Default DA/CCA Customers to TOU Rates and Eliminate DA/CCA Flat Rate Options	3-5 months
New Optional Demand Charge Rate (Small Commercial)	3-5 months
A10 New Peak Demand Charge; or flatten current charge seasonally	3-5 months
Add distribution time differentiation to , A1 and A10 TOU	3-5 months
A1/A6 maximum eligibility threshold lowered to 20 kilowatts (kW) (from 75 kW)	3-5 months
Eliminate A6 Solar Pilot for E19 Customers	3-5 months
Food Bank Eligibility for E-CARE and G-CARE (AB2218)	30 days
Continued increase in TOU differentials for A1 TOU	30 days
Residential	
Update Residential Electric Baseline Quantities for all schedules to 4-month summer season.	4-6 months
Eliminate Power Charge Indifference Adjustment Exemption for Med Baseline and DA/CCA	3-5 months
Add distribution time differentiation to ETOU.	3-5 months
Expand Territory Q to include additional customers in Santa Cruz County and San Lorenzo Valley, use the same baseline quantities as those calculated for Territory X.	1-3 months
Revise gas baseline quantities at the same percentage of average use as in previous GRC Phase II proceedings.	30 days

The TOU Time Period Change and new Ag rates will require nine to twelve months for systems changes. All other proposed changes can be implemented within six months of a decision.

4. Funding

PG&E has requested funding in the 2017 GRC Phase I proceeding for customer education and outreach for non-residential TOU time period change. If that funding request is not adopted, PG&E requests that a Memorandum Account be established at the time of the 2017 GRC Phase II decision in order to allow general awareness education and outreach about TOU Time period change to begin as soon as possible after a final decision in this proceeding (expected in or about late 2017).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 11

ECONOMIC DEVELOPMENT RATES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
ECONOMIC DEVELOPMENT RATES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
ECONOMIC DEVELOPMENT RATES

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) proposal for economic development rates (EDR) in its 2017 General Rate Case (GRC) Phase II. PG&E proposes to extend the offering of its current Standard and Enhanced EDR tariffs until December 31, 2020 and to increase the participation cap by an additional 200 megawatts (MW), with an option for an additional 200 MW, for the period 2018 through 2020.

B. Overview of the EDR Program

On November 13, 2012, PG&E filed Application 12-03-001, *Application for Approval of Economic Development Rate for 2013-2017* to extend and revise its economic development rates.

On October 3, 2013, the Commission issued Decision (D.) 13-10-019 which authorized PG&E to offer an EDR tariff.

The EDR Program offers a discounted electric rate over a 5-year period to help bring new businesses to California and retain companies that are already here. The EDR Program is applicable for the expansion, retention and attraction of customers with loads of at least 200 kW that have viable non-California location options, or are intending to cease operations in California altogether. It is designed to generate revenue in excess of marginal cost plus Non-Bypassable Charges (NBC) for the benefit of PG&E's remaining customers,[1] and respond to the distinct needs of different parts of PG&E's service area. There are two rate options under the EDR Program:

1. A Standard EDR Option which provides a 12 percent rate reduction for five years.
2. An Enhanced EDR Option which is available in cities and counties with unemployment rates greater than 125 percent of California's annual average. This option provides a 30 percent rate reduction for five years.

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1 See D.13-10-019, Appendix A, mimeo, p. A-1, bullet 5.

Pursuant to D.13-10-019, the EDR Program has a programmatic cap of 200 MW. The CPUC further established a requirement that PG&E achieve a 5 percent reduction in energy usage across all of the participants on the EDR tariff over the life of their contracts. PG&E encourages program participants to implement Energy Efficiency (EE) measures and participation in Demand Response Programs (DRP) at their participating facility.

Finally, pursuant to D.13-10-019, the EDR Program will no longer be available to new customers upon the effective date of rates implementing a decision in PG&E's 2017 GRC Phase II proceeding, unless otherwise extended in this proceeding.[2]

C. EDR Program Participation

1. Enrollment

The EDR Program, which began enrollments in 2014, had a total of fourteen participating customers representing fifteen separate EDR contracts at the end of 2015.

During the first year of the program, in 2014, PG&E enrolled two customers onto its Standard EDR and five customers onto its Enhanced EDR, for a total of seven customers. Of these seven customers, three took advantage of a DRP and achieved energy savings of approximately 262,000 to 263,000 kilowatt-hours (kWh). It is estimated that program operations in 2014 alone resulted in the creation or retention of 662 California jobs, with a total of $17,882,117 in total combined salary and benefits.

During the program's second year of operations, in 2015, PG&E enrolled four more customers onto its Standard EDR, and one more customer onto its Enhanced EDR, as well as, one business customer with multiple facilities, who has one enrolled under the Standard EDR and another one enrolled under the Enhanced EDR. Of the 13 total EDR customers (representing a total of 14 EDR contracts) participating in the program in 2015, eight took advantage of a demand response or EE program and achieved savings of 228,000 to 229,000 kWh.

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2 D.13-10-019, mimeo, p. 38.

This resulted in the creation or retention of 2,115 California jobs, with a total of $2,363,923,649 in combined salary and benefits in 2015.

As of the end of April 2016, two more customers began service under the Standard EDR and one customer began service under the Enhanced EDR.

2. Revenue Evaluation

The ability to offer customers a rate option that allows PG&E to attract or retain sales that otherwise would not have located or been retained in California results in total sales that are higher than they otherwise would be absent these customers. To the extent PG&E can retain or attract sales at a rate that is lower than the tariffed rate, but higher than the marginal cost helps to maintain or add to Contribution To Margin (CTM). This CTM can be used to keep rates to non-participating customers lower than they would otherwise be. If the customer instead did not locate or maintain business operations in California, this CTM would be lost, depriving ratepayers of the associated benefit. D.13-10-019 established the expectation that revenue from participating customers not only exceed marginal cost, but also exceed the total of distribution and generation marginal cost plus NBCs, on a program-wide basis. Further, D.13-10-019 provides that if PG&E would like to continue offering the options beyond the effective date of the Phase II 2017 GRC, then PG&E should include a firm showing of programmatic positive CTM, and full payment of NBCs in its 2017 Phase II GRC application.[3]

Accordingly, PG&E's has conducted its analysis of revenue under two scenarios:

a. Contribution To Margin

PG&E compared the revenue from EDR participants to the marginal cost consisting only of marginal economic costs applicable to customers

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[3] D.13-10-019, mimeo, pp. 2 and 3. NBCs include transmission charges, Public Purpose Program Charges, Nuclear Decommissioning Charges, Competition Transition Charges, New System Generation Charges, Department of Water Resources Bond charges (and for direct access and community choice aggregation customers, the Power Charge Indifference Adjustment). Additionally, NBCs should also include Energy Cost Recovery Amount which was not specifically listed.

receiving the EDR over a short term: Marginal Generation Energy costs (Marginal Generation Capacity costs are excluded pursuant to D.13-10-019); Transmission Charges;[4] Marginal Customer Access Costs; and Marginal Distribution Capacity Costs to the extent the customer is located within a constrained Distribution Planning Area. All marginal cost values were used as adopted for contract evaluation purposes in the Marginal Cost and Revenue Allocation Settlement adopted by D.15-08-005 in PG&E's 2014 GRC Phase II. Under this analysis, on a calendar year basis, the participants contributed positive CTM in the amount of $3.7 million for 2014 and 2015. However, it is important to note impacts from and limitations of using a calendar year versus the 12-month period from commencement of each such customer's EDR contract date. For customers who do not have billing data covering every month in 2015, the estimated CTM may not be accurate. Therefore, PG&E believes that using billing data across a 12-month period from contract anniversary dates may better reflect the revenue from Schedule EDR customers than does a calendar year analysis. Thus, PG&E is also providing the requested CTM revenue analysis for the subset of seven customers, who had completed their first full contract year in 2015. The CTM analysis excludes the revenue from partial contract years for these customers, as well as, the revenue from EDR customers who had not yet completed their first full contract year. Using a contract year approach, the calculated CTM for these seven EDR customers is $1,818,402. Using either approach, EDR customers provided a positive CTM.

b. Revenue Contribution

PG&E compared the revenue from EDR participants with the marginal cost (described above in the analysis of CTM), plus all the components in Section 2.a above and all NBCs. Under this analysis, on a calendar year basis, the participants contributed revenue in excess of this amount by $2.1 million for 2014 and 2015. However, it is important

[4] Approved transmission rates were used as a proxy for transmission marginal cost and are therefore part of the marginal cost used for the CTM evaluation.

to note impacts from and limitations of using a calendar year versus the 12-month period from commencement of each such customer's EDR contract date. For customers who do not have billing data covering every month in 2015, the estimated revenue may not be accurate. Therefore, PG&E believes that using billing data across a 12-month period from contract anniversary dates may better reflect the revenue from Schedule EDR customers than does a calendar year analysis. Thus, PG&E is also providing the requested CTM revenue analysis for the subset of seven customers, who had completed their first full contract year in 2015. The revenue analysis excludes the revenue from partial contract years for these customers, as well as, the revenue from EDR customers who had not yet completed their first full contract year. Using a contract year approach, the calculated revenue for these seven EDR customers is $820,210. Using either approach, EDR customers provided positive revenue. Thus, all marginal costs were recovered and NBCs are fully funded.

Under either the CTM or Revenue Contribution analysis, PG&E's EDR Program was shown to provide benefits to non-participating ratepayers, from customers who would have otherwise located out of state, or ceased their business operations in California.

D. Economic Conditions in California Justify the Continuation of PG&E's EDR Options

While economic conditions have improved since PG&E filed its original EDR application in 2012, California continues to lag the nation in its economic recovery. As reported by the state of California's Economic Development Department, for the month of January 2016, California's unemployment rate was 5.7 percent, compared to 5.0 percent nationwide. Unemployment rates in many cities and counties within PG&E's service area are even higher. Currently, the following counties are reported by the Economic Development Department's 2015 "Report 400 C, Monthly Labor Force Data for Counties, Annual Average 2015 – Revised," as having an unemployment rate of at least 125 percent of the state's average annual unemployment rate of 6.2 percent (i.e., an unemployment rate of 7.75 percent or greater) in 2015;

TABLE 11-1
COUNTIES IN THE PG&E SERVICE AREA WITH A 2015 UNEMPLOYMENT RATE AT LEAST 125 PERCENT GREATER THAN CALIFORNIA'S 2015 AVERAGE UNEMPLOYMENT RATE OF 6.20 PERCENT

Line No.	County	2015 Annual Unemployment Rate
1	COLUSA	15.30%
2	TULARE	11.70%
3	MERCED	11.40%
4	SUTTER	10.80%
5	KINGS	10.50%
6	MADERA	10.50%
7	PLUMAS	10.40%
8	FRESNO	10.20%
9	KERN	10.20%
10	STANISLAUS	9.50%
11	SISKIYOU	9.40%
12	YUBA	9.20%
13	SIERRA	9.00%
14	SAN JOAQUIN	8.90%
15	GLENN	8.70%
16	MONTEREY	8.10%
17	TEHAMA	8.00%
18	ALPINE	7.90%
19	SHASTA	7.80%
20	TRINITY	7.80%

To provide meaningful change in these impacted areas, particularly for companies that are sensitive to electric costs, PG&E's EDRs are a means by which PG&E can work with local, regional and state economic partners to enhance California's competitiveness as a business location. In turn, the newly attracted or retained businesses create or retain jobs which provide benefits for California residents and PG&E's customers. As evidenced by the results to date, PG&E's Standard and Enhanced EDR options have been successful in retaining or attracting qualified customers. Of particular note, the EDR Program was able to get nine companies to choose to locate to or remain in cities and counties that are experiencing high unemployment rates (i.e., unemployment rates equal to 125 percent or more of the state's average annual unemployment rate), as reported by the Economic Development Department. It remains important to attract and retain jobs to help support the continued recovery of the California economy.

E. PG&E's Proposed EDR Options

PG&E is proposing to extend its current Standard and Enhanced EDR tariffs until December 31, 2020. As of November 1, 2016, PG&E projected that, between its existing and reserved economic development commitments, it has about 128 MW remaining out of the currently-approved 200 MW cap that is still available for new EDR contracts. This amount is likely to be insufficient to respond to attraction and retention needs through 2020, because state- and local economic development teams continue to seek to attract new loads or to retain loads that would otherwise leave. Therefore, to avoid a scenario where a potential economic development customer, or customers, might be lost to California because the EDR Program cap was set too low, PG&E requests that its cap be increased by an additional 200 MW, with an option to increase the program cap by another 200 MW through the submittal of a Tier 2 Filing to the Commission if the remaining load space is insufficient to maintain a viable program through December 31, 2020.

As noted above, the analysis of revenue from participating customers fully supports continuation of this important job-promoting program. To be sustainable going forward, however, PG&E believes that new program enrollment must be must be supported by an evaluation of current marginal costs and rates. PG&E's analysis of the program on a forward-looking basis utilizes schedule-average rates (based on rates effective October 1, 2016) and marginal costs as proposed in this proceeding for Schedules A-10S, E-19P, E-19S, E-20T, E-20P, and E-20S. PG&E calculated the maximum discount that could be applied to each of these rate schedules on a schedule-average basis, based on all revenue in excess of transmission charges, generation marginal energy costs, constrained distribution marginal capacity costs, and marginal customer access costs. PG&E also calculated the maximum discount possible based on all the marginal cost described above and NBCs. As shown in Table 11-2, in all cases, PG&E found that the maximum discount achievable exceeded the 30 percent maximum discount on EDR. Thus, PG&E believes that discounts approved by the Commission as a part of D.13-10-019 are sustainable going forward for the current and expanded EDR Program. Based on this analysis, PG&E concludes that the program discounts approved by D.13-10-019 are reasonable and should be continued.

TABLE 11-2
MAXIMUM ALLOWABLE EDR DISCOUNTS BASED ON CONSTRAINED DISTRIBUTION MARGINAL COST AND RATES EFFECTIVE OCTOBER 1, 2016

Line No.		Maximum Discount Relative to Marginal Cost	Maximum Discount Relative to Marginal Cost Plus NBCs
1	Schedule A-10S	53.3%	41.4%
2	Schedule E-19P	55.7%	42.0%
3	Schedule E-19S	58.0%	44.9%
4	Schedule E-20T	57.4%	40.6%
5	Schedule E-20P	57.0%	43.0%
6	Schedule E-20S	56.8%	43.3%

F. Conclusion

California's unemployment rate continues to lag the nation and its energy rates are a disincentive for energy price-sensitive customers to remain or locate within the state. Attracting new businesses or retaining existing businesses creates or retains jobs and provide benefits for California residents generally and PG&E customers specifically. Over the past two years, PG&E's EDR Program has created or retained 2,115 jobs, contributing over $2.363 billion in combined salary and benefits to the California economy. More importantly, eight of these customers chose to remain in or establish new businesses in cities and counties with unemployment rates higher than the state average. The Commission should adopt PG&E's EDR proposals presented herein.